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Activities Implemented Jointly in India

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1 Introduction

One of the most important agreements to have come into existence during the Rio Summit in 1992 is the UN Framework Convention on Climate Change (FCCC). The FCCC aims at stabilizing the anthropogenic emissions of greenhouse gases (GHGs) at certain specified levels, and protecting the climate system for the benefit of present and future generations. The Joint Implementation (JI) mechanism or Activities Implemented Jointly (AIJ) is one of the instruments provided under the Convention to enable the member Parties meet their respective commitments cost-effectively on a global basis.

The JI mechanism enables countries to undertake cooperative efforts and measures to reduce the net GHG emissions. The idea of JI is that countries with higher marginal costs of GHG emissions reduction (usually the industrialized countries) would implement projects jointly in countries where the marginal costs are lower (usually the developing countries or economies in transition). Here, the former country or group of countries would provide the technological and/or financial inputs, and in return get credits for abatement of GHG emissions that occurs due to the activity. JI, thus, can be viewed as a voluntary agreement between the investing Party that would provide the financial and/or technological inputs; and the host Party that would provide the opportunity for cost-effective emission reduction or the project site.

The concept of JI is still evolving, and there exist uncertainties regarding the working of the mechanism. Thus, the first meeting of the Conference of Parties (COP-1) to FCCC in 1995, established a pilot phase for AIJ among developing and developed countries without any transfer of credits to any Party, extending up to the end of the decade. The Pilot Phase has been set up as an experimental phase to gain confidence in the mechanism, and to demonstrate the viability of JI as a practical and equitable strategy for helping to meet the objectives of the FCCC. It was decided that AIJ should:

- be compatible with and supportive of national environment and development priorities and strategies
- contribute to cost-effectiveness in achieving global benefits
- require prior assistance, approval and endorsement by the Governments of the participating Parties
- should generate real, measurable and long-term environmental benefits related to mitigation of climate change that would have not occurred in the absence of such activities.

Benefits under AIJ

Besides addressing the global problem of climate change in a cost-effective manner, AIJ has significant benefits for both the investing and host Parties. The benefits accruing to the host parties include financial and technological inputs (particularly from the private entities), capacity building, local environmental benefits, and indirect benefits like employment generation, and establishing international contacts. For the investing country, on the other hand, the benefits include increased potential for technology transfer and market access, an opportunity to establish a lead in abatement activities, creating a 'green image', indirect effects, like lowering the costs of green technologies and increasing international credibility.

In addition to these, AIJ also provides an opportunity for all Parties to gain experience and build their information base. Once the Pilot Phase concludes, and the JI mechanism becomes operational with credits as CDM or in any form, abatement credits are expected to be transferred/shared by the participating Parties for the cooperative abatement activity.

The Clean Development Mechanism

At the third meeting of the COP (COP-3) in 1997, a Protocol to the FCCC also known as the Kyoto Protocol was adopted for strengthening the commitments of the Parties. The Protocol introduced two project level cooperative mechanisms:

1. Joint Implementation between developed country Parties, and
2. Clean Development Mechanism (CDM) between developed and developing countries.

The purpose of the CDM as indicated in Article 12 of the Kyoto Protocol, is to assist:

- Non Annex Parties: in achieving sustainable development
- Annex I Parties: in achieving compliance with their emissions limitation targets

The benefits that would accrue are:

- To the Non-Annex I Parties: profit from project activities resulting in certified emissions reduction
- To the Annex I Parties: may use the certified emissions reductions accruing from such project activities to contribute to compliance with part of their emission limitation targets.

The emissions reductions resulting from each of the project activity shall be certified by operational entities to be designated by the COP/Meeting of the Parties to the Protocol, on the basis of:

1. Voluntary participation approved by each Party involved
2. Real, measurable, and long term benefits related to the mitigation of climate change
3. Reduction in emissions that are additional to any that would occur in the absence of the certified project activity.

These certified emissions reduction obtained during the period from the year 2000 up to the beginning of the first commitment period can be used to assist in achieving compliance in the first commitment period. The COP/ Meeting of the Parties to the Protocol shall at its first session, elaborate modalities and procedures with the objective of ensuring transparency, efficiency and accountability through independent auditing and verification of project activities.

An important provision of this Article is that a share of the proceeds from the certified project activities is used to cover administrative expenses as well as to assist the developing country Parties that are particularly vulnerable to the adverse effects of climate change to meet the costs of adaptation.

The CDM mechanism can be visualized as a formalized JI mechanism between the developed and developing countries with exchange of credits. The AIJ phase between Annex I and non-Annex I parties is expected to give way to CDM in the year 2000. However, the modalities involved have not yet been discussed. The experiences gained in the Pilot Phase would help in developing and formalizing them.

Scope of the study

The scope of the study "*Activities Implemented Jointly (AIJ) in India*" is:

- Overview and status of AIJ projects that are being planned, implemented or completed by Annex I countries.
- Identification of potential AIJ/CDM projects in line with the policies of the Indian government.
- Developing proposals or ideas for implementation as AIJ/CDM projects, which could be undertaken co-operatively with Japan.
- Recommendations for identifying the potential projects and investors, receiving approval/endorsement from the respective governments, and implementing AIJ/CDM projects in India.
- Forecast of the future prospects of AIJ/CDM in India.

Methodology

The methodology for this study is based upon meetings and case studies.

At a Joint NEDO-EPDC-TERI* Round Table on *'Initiatives to promote Indo-Japanese co-operation for clean and efficient energy'* organised at New Delhi on 25th January 1997, the potential areas for implementing Indo-Japanese AIJ projects were discussed. Seventeen most polluting industries in India were also listed. These included: Cement, thermal power plants, iron and steel, fertilizers, zinc, cooper, aluminium smelters, oil refineries, distilleries, pulp and paper, pharmaceuticals, dyes and dye intermediates, pesticides, petroleum, petrochemicals, tanneries, sugar and basic drugs. Of these, three major sectors were been identified as the areas of focus for this study, which were significant from both Indian and Japanese point of view. These are:

1. conventional power
2. iron and steel
3. cement sectors.

The work was divided into two phases. The first round involved disseminating AIJ-related information and apprising the industrial houses about the concept of AIJ, the opportunities existing, and the modalities and issues involved. Attempts would be made to identify the types of potential projects, and providing preliminary recommendations for their development and implementation. In this effort, a lot was drawn upon by work done by us under a programme initiated by TERI entitled *'TERI Repository on Environmental Activities and Technologies (TREAT)'*.

The second phase involved developing ideas and case studies for implementing potential co-operative projects between India and Japan, as well as providing recommendations for the same.

TREAT

TREAT is a programme launched by TERI, which involves information dissemination and exchange; developing in a proactive manner, a portfolio of potential abatement projects in India; and providing technical assistance to implement such projects. The initial focus of this programme is to develop projects that lend themselves to the AIJ/CDM criteria.

The main activities under TREAT can be divided into two broad headings: General and project related. These are briefly listed below.

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* New Energy and Industrial Technology Development (NEDO), Japan, Electric Power Development Corporation (EDPC) and the Tata Energy Research Institute, India.

General activities

- Awareness creation and information dissemination in order to boost the AIJ programme in India.
- International linkages and networking.
- Streamlining of a pipeline of potential projects in India in line with the national priorities and policies and with the criteria for AIJ laid down by COP.
- Clearinghouse activities and exchange of information among prospective participants.
- Analysing the projects and providing policy recommendations regarding the working of the pilot phase of AIJ.

Project-related activities

Support activities and technical assistance. Support services related to specific projects would be provided to the partners in order to ensure that mutually beneficial agreements are negotiated while keeping in mind the ultimate objective of reducing GHG emissions. This would be done while maintaining the transparency and objectivity of TREAT, and would not in any way reflect the private interests of any of the Parties involved. The services provided would include the following.

- Assistance in developing credible proposals
- Helping in environmental negotiations between the potential partners
- Developing Management Information System (MIS).

Under this programme, a workshop on *'Activities Implemented Jointly: opportunities and issues'* was organized by TERI in June 1998, at New Delhi, India. The experiences at this workshop and its outcome are drawn upon for use in this project. About 80 participants attended the workshop, including representatives of several major corporate houses in India.

The primary objective of this workshop was to sensitize the corporate sector about the issues and opportunities related to AIJ. The first session concentrated on introducing the concept and discussions on general issues. Then, the participants were divided into five working groups (Renewables, Industry, Forestry, Power and Coal, and Petroleum and Gas) in which more focused discussions were held. Several project ideas were developed and discussed. These included rooftop solar PV systems, solar thermal devices, projects in cement and steel industries, afforestation, clean coal technologies for power generation, renovation and modernization of power plants, cogeneration, CNG vehicles, alcohol-blended gasoline and biofuels. These included some of the case studies that have been included in this report.

The workshop brought out the willingness of the corporate sector to exploit the opportunities available under AIJ/CDM. They expressed the need for better policies on part of the Government of India to facilitate this process. A list of participants that have shown keen interest in this mechanism is included as Annexure I.

2 Status of AIJ

As of now, there were 103 projects that had been accepted, approved and endorsed by the designated national authorities for AIJ of the host and investing Parties and have been or will be reported to the FCCC Secretariat (JIQ June 1997). The geographical spread and the range of projects covered still need a lot to be desired.

Till the seventh session of SBSTA (Subsidiary Body on Scientific and Technological Advice) in October 1997, where a synthesis report on AIJ was presented, only thirty nine activities, involving 11 countries have been submitted to the FCCC Secretariat. A detailed consideration of the programmes and activities on which reports were received allowed some preliminary conclusions, which included the following (SBSTA 1997):

(a) The bulk of current AIJ is between Annex I Parties, with host countries being economies in transition. Only three non-Annex I Parties have AIJ of which nine activities are in Latin America and the Caribbean and one activity is in Africa. The regional concentration is even more pronounced considering that, of a total of 39 activities, 18 involve the same two Annex I Parties (Latvia and Sweden) and that one country in the Latin American and Caribbean region (Costa Rica) hosts eight of the ten activities in non-Annex I Parties.

(b) The total amount of greenhouse gases (GHG) estimated to be reduced or sequestered by 39 activities considered is distributed over the various types of activities. Six forestry preservation and afforestation activities account for 57 per cent of the abatement impact and 34 per cent are attributable to one fugitive gas activity. Twenty-nine activities related to energy account for 9 per cent of the GHG abatement effect. Most AIJ under the pilot phase are relatively small in terms of investment and their individual contribution to GHG abatement is limited. A more significant effect would, however, be achievable through the replication of such projects.

A number of countries have drafted their AIJ prgrammes, including Japan. As of now there are twenty countries with (planned) official AIJ projects. However, it is expected that most of these programmes would be modified in due course, in light of the interest generated by the introduction of CDM in the Kyoto Protocol.

The Indian Scenario

The Indian Government is adopting a very open approach to the idea of AIJ and has set up a '*Task Force on AIJ*' to recommend and evaluate projects. The nodal ministry for the Task Force is the Ministry of Environment and Forests (MoEF). It includes representatives from various other concerned Ministries as well as non-governmental organizations (NGOs) working in the area. Currently, there are five projects that have been approved by this Task Force (see table 1), out which two are with Japan as the Investing Party. The government is looking for more proposals to be undertaken as AIJ projects (without credits) at this stage. However, the government's position on CDM is yet not clear.

Table 1 Pilot Phase AIJ Projects endorsed by the Government of India

	Name of the Project	Location	Investing Party	Host Party
1	Direct Reduced Iron (DRI)	Gujarat	Japan	M/s Essar, Gujarat, India
2	Energy recovering from waste gas and liquid	Gujarat	Japan	IPCL Plant at Vadodara, Gujarat, India
3	Integrated Agricultural DSM	Andhra Pradesh	World Bank	Andhra Pradesh State Electricity Board, India
4	DESI – Power: biomass gasification	At 20 sites	The Netherlands	DESI Power, Development Alternatives, India
5	Tamarin Orchard Agro Forestry for Dry Land	Karnataka	USA	ADAT, Bagepalli, Karnataka, India

There are a number of projects, which limit or reduce GHGs emissions or increase their removals by protecting or enhancing GHGs sinks and reservoirs, which can be implemented as AIJ projects in India. Some examples of the potential AIJ/CDM include:

- Fuel switching projects.
- Demand side management.
- Cogeneration projects.
- New and emerging technologies in the power sector.
- Renewable energy technologies for power generation.
- Agro-forestry options.

The project proposals submitted to the Task Force for approval should in line with the COP decisions, and contain the following information (see box 1):

- Objective of the project
- Target GHG(s)
- Technology details

- Projected benefits (both local and global)
- Financial aspects of the project and cost sharing
- Sharing of benefits
- Methodology for monitoring and tracking of GHGs
- Details of methodology for estimating the GHG reductions
- Potential GHG reductions .
- Details of the prefeasibilty study if it has been undertaken
- Feasibility of the future adoption of technology
- Reasons for not proposing the project under any other bilateral arrangement vis-à-vis reasons for it being an AIJ proposal.

Box 1 : AIJ Project Criteria Proforma
Ministry of Environment and Forests, Government of India

In order to consider a project for endorsement by the government of the host country some details on the AIJ context of the project have been requested which may be provided are:

1. Title of the Project
2. Sector of Activity
3. Target Greenhouse Gas/es
4. Objectives
5. Outline of the Technology
6. Current Status of technology in India
7. Current status of technology in the World
8. Details of cost effectiveness of the Technology
   8.1 National Benefits (Projected Quantitative Benefits)
   8.2 Global Benefits (Projected Quantitative Benefits)
9. Does the project bring about real, measurable and long term Environmental benefits.
10. Cost of Reduction of GHGs.
11. Financial Resources
    Donor Component
    Host Component
12. Sharing of Benefits
    12.1Treatment (Theoretical) of the question of sharing of benefits between donor and host country.
    12.2 Intellectual Property Rights, if any
13. Monitoring and Tracking of GHGs.
    13.1Methodology of Tracking and Monitoring of GHGs
    13.2 Details of the calculation Procedure for Estimate of Green House Gas Reductions.
    13.3 Total Green House Gas (GHG) Reductions
      a)With reference to current levels
      b) Potential GHG Reduction in the sector of activity
14. Has any prefeasiblity study undertaken ? If so details thereof.
15. Feasibility and future adoption of Technology in the sector of the activity
16. Reasons for not proposing the project under any other bilateral arrangement vis-a vis reasons for its being an AIJ Candidate Proposal.

Japanese AIJ Programme

The Government of Japan established the '*Japan Programme for AIJ under the Pilot Phase*' in November 1995. Besides the criteria that support decision on criteria in the pilot phase laid down by the COP-1, the other national criteria includes:

- Project implementation entities shall regularly review predictions and modify them as appropriate. They shall inform the competent ministry/agency of the modification.
- The environmental, economic, and social impacts of the proposed project shall be adequately assessed. The results shall be reviewed by the relevant authorities as appropriate.

The first public invitation to participate in the AIJ Japan Program took place from 1 April 1996 until 10 June 1996. During the first round the Japanese ministries approved eleven projects as potential AIJ projects in July 1996. After negotiations between the Japanese governmental executive entities and the host country representatives for each project, three projects has very recently received approval from the host country governments (China, Indonesia and Thailand). These are as follows.

1. Coke dry quenching project in China
2. 2. Waste-heat recovery investment at a steel heating furnance at a steel heating plant of the Siam Iron and Steel Company Limited located in Saraburi (near Bangkok) in Thailand and ;
3. Efficiency improvement of sludge and solid waste combustion in a paper mill at a plant of Pt. Fajar Surya Wiseasa located in West Java in Indonesia.

In order to support the development of AIJ/JI/CDM projects, for the budget year 1998 the Japanese Ministry of International Trade and Industry (MITI) has reserved US$ 15.4 m (maximum US$ 0.62 m per project) for feasibility studies of potential AIJ/JI/CDM projects.

In addition to the funding from MITI for feasibility studies, there are three channels through which the Government of Japan can stimulate international carbon offsets through public funds (JIQ 1998)::

- **The Green Aid Plan**

  This fund was implemented in 1992 by MITI with a funding mechanism in addition to the ODA. The three Japanese AIJ projects that have recently been approved were initiated under the Green Aid Plan. The plan mainly focuses on six countries in Asia (Indonesia, China, Thailand, Philippines, Malaysia, India) and its budget is limited to about 14 billion yen (about US$ 100 m) for the budget year 1998.

- **Export-Import Bank loans**

The Japan Export-Import Bank offers loans with interest rates of 2-3% per annum.

"Environmental super interest"

The third type of fund is the financial cooperaton (grant and loan) through ODA. For global warming abatement projects, the applied loan interest rate will be the "environmental super interest" (interest rate of 0.75% per annum) as announced by the Japanese delegation just before the Kyoto Conference. Using this fund for AIJ/JI/CDM, however, may create a problem with respect to the additionality requirement for AIJ/JI/CDM under the CoP1 decision in Berlin. The available funds for the Export-Import Bank loans and ODA global warming abatement projects are significantly larger than those of the Green Aid Plan.

Box 2. Evaluation Criteria for AIJ projects
The Japanese AIJ Programme

The competent ministry/agency, which is to supervise a relevant AIJ project, shall ensure that the proposed project would satisfy the following requirements, in approving it as AIJ under the Japan Programme:

- Predicted results of GHG emissions (or absorption) shall be presented both with and without the proposed project, together with sufficient information on their prediction. Emissions projected with the project shall be less than that without the project, or absorption projected with the project shall be more than that without the project.
- Cumulative effects of GHG emission reduction resulting from the proposed project shall not be negative.
- Project implementation entities shall regularly review predictions and modify them as appropriate. They shall inform the competent
- ministry/agency of the modification.
- The proposed project shall be additional to the financial obligations of the Parties set out in Article 4.3 of UNFCCC as well as to current official development assistance (ODA) flows.
- The proposed project shall be agreed upon as AIJ by the governments of partner Parties.
- The proposed project shall not cause greater increase in GHG emissions in other areas compared with the reduction of GHG emissions expected from the project.
- The environmental, economic, and social impats of the proposed project shall be adequately assessed. The results shall be reviewed by relevant authorities as appropriate.

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As written in the papers

Option	First Paper (units)		Second Paper (units)	
Pulverized coal super-critical boilers	-4.9	$/t CO2	0.02	$/kg CO2
Atmospheric fluidized bed combustion	-2	$/t CO2	0.009	$/kg CO2
Pressurised fluidized bed combustion	4.2	$/t CO2	-0.025	$/kg CO2
Integrated gasification combined cycle	0.5	$/t CO2	0.02	$/kg CO2
Combined cycle generation (Natural gas)	6.2	$/t CO2	-0.033	$/kg CO2
Bagasse based cogeneration	-4.36	$/t CO2	-7.778	$/kg CO2
Dry precalciner kilns	none		214.28	$/t CO2
Dry suspension preheater kilns	none		6.95	$/t CO2
Small hydro	88	$/t CO2	0.36	$/kg CO2
Wind farm	257	$/t CO2	-0.02	$/kg CO2
Biomass Power	102	$/t CO2	-0.008	$/kg CO2
Solar thermal	592	$/t CO2	disappeared	
Photovoltaic	541	$/t CO2	0.18	$/kg CO2
Agro-waste based gasifiers	119	$/t CO2	-0.092	$/kg CO2
Wood-waste based gasifiers	115	$/t CO2	-0.072	$/kg CO2
Wind shallow well	173	$/t CO2	0.105	$/kg CO2
Wind deep well	176	$/t CO2	0.088	$/kg CO2
PV pump	1602	$/t CO2	2.708	$/kg CO2
All iron and steel options	none		none	

1. Bagasse based cogeneration,
2. Combined cycle gas turbines – natural gas based.

Iron & steel
1. Direct reduction process
2. Basic oxygen furnace

Cement
1. Dry suspension preheater kilns
2. Dry precalciner kilns

Renewables for power generation
1. Biomass based power generation
2. Small hydro

Renewables for irrigation
1. Agro-waste based gasifiers
2. Wood-waste based gasifiers

Annexure 1a

Technology : Conventional Power Generation (excl. Bagasse Based Cogeneration)							
PLF	80.00%						
Technical and other design parameters		PC (SUBC)	PC (SUPC)	AFBC	PFBC	IGCC	CCGT
Capacity of power plant	MW	500	500	500	500	500	500
Fuel		Dom coal	Dom coal	Dom coal	Dom coal	Dom coal	NG
Configuration		1x500	1X500	2X250	2X250	1x500	1x500
Aux cunsumption	%	6.00%	6.00%	6.00%	5.00%	20.00%	1.69%
Gross Heat rate	kcal/kWh	2260	2150	2000	1912	1480	1593
Capital cost breakdown	Rs.Crores						
Total no of operating HOURS	hours	7008	7008	7008	7008	7008	7008
Net capacity	MW	470	470	470	475	400	492
Gross generation	Mwh	3504000	3504000	3504000	3504000	3504000	3504000
Net generation	Mwh	3293760	3293760	3293760	3328800	2803200	3444782
Net heat rate	kcal/kwh	2404	2287	2128	2013	1850	1620
Net Efficiency	%	36%	38%	40%	43%	46%	53%
Net Fuel consumption	tonnes/yr	1979760	1883400	1752000	1674912	1296480	637200
Annual cost	Rs.million	3128	2976	2768	2646	2048	1838
EPC Turnkey	Rs.million	13710	15130	16011	15008	19500	10797
PDC	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Land	%	1.00%	1.00%	1.00%	0.50%	0.50%	0.50%
IWC	%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Cont.	%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
FHS	%	2.55%	2.31%	2.00%	2.00%		
AD +fgd	%	4.45%	4.03%	4.00%	2.50%	4.00%	
IDC	%	20.43%	20.43%	20.43%	12.25%	12.25%	12.25%
		40.93%	40.27%	39.93%	29.75%	29.25%	25.25%
Financial Cost Analysis							
Total project cost	Rs million	19322	21223	22404	19473	25204	13523
CRF (F)	%	14.38%	14.38%	14.38%	14.38%	14.38%	14.38%
Fixed O&M cost	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Annual O&M cost	Rs million	483.04	530.57	560.10	486.82	630.09	338

Converted to $/t of carbon

First paper ($/tC)	**Second paper** ($/tC)
-18	73
-7	33
15	-92
2	73
23	-121
-16	-28545
none	214
none	7
323	1321
943	-73
374	-29
2173	disappeared
1985	661
437	-338
422	-264
635	385
646	323
5879	9938

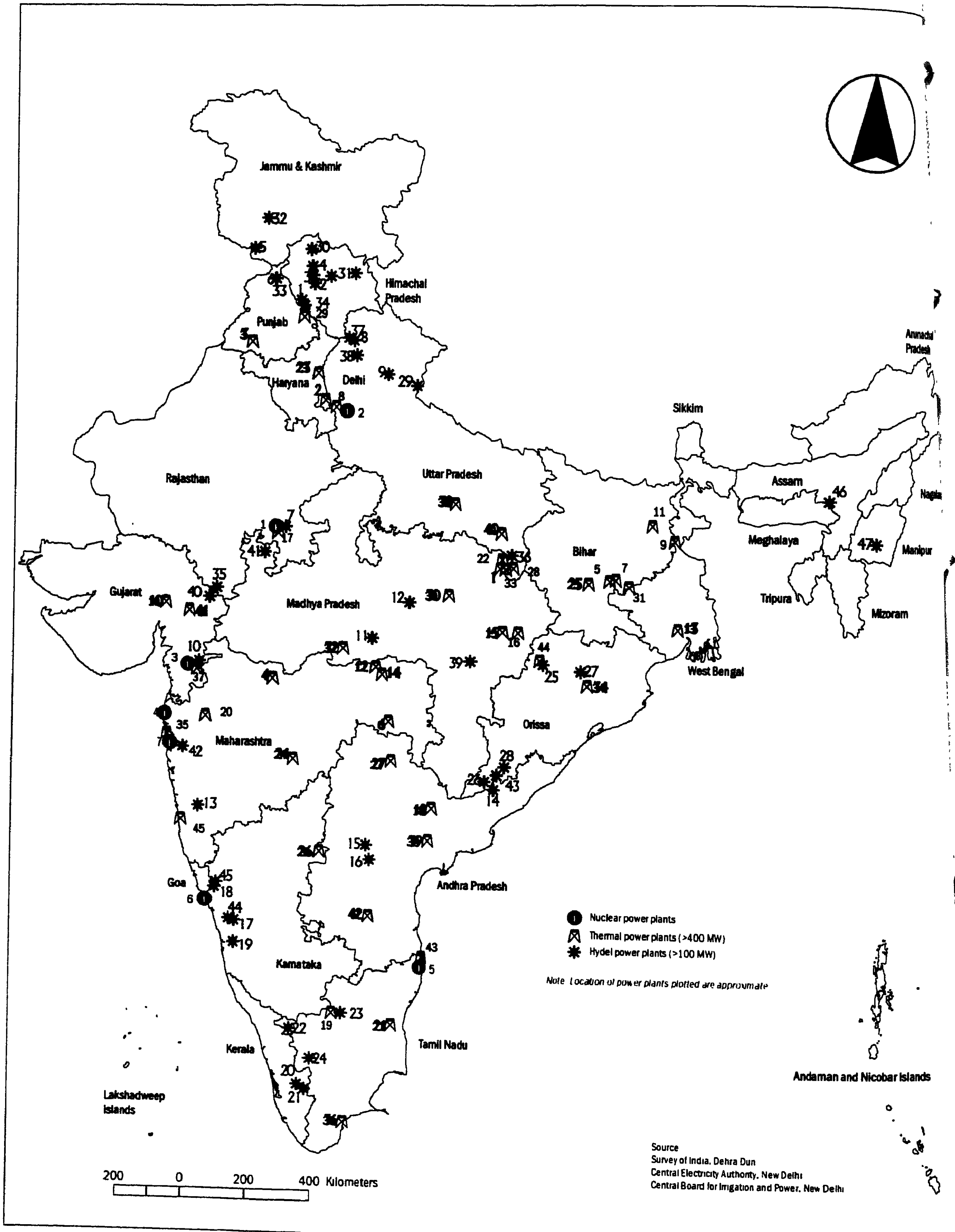
	Agro-waste based gasifiers	Wood-waste based gasifiers	Wind shallow well	Wind deep well	PV pump	Small hydro	Wind farm	Biomass power	Solar thermal	Photo Voltaic
						Investment cost (US $/kW)				
Investment cost (US $/kW)	760	694	1157	2149	8598	1950	1405	710	3730	5952
utilisation	3504	3504	1200	1200	624	3504	2628		3504	1560
Capital cost per kwh	0.216895	0.198059	0.964167	1.790833	13.77885					
						GHG emission reduction (kg/kWh)				
GHG emission reduction (kg/kWh)	1.6	1.6	1.6	1.6	1.6	1.3	1.3	1.6	1.3	1.6
						Cost effectiveness (US $ /t CO2 reduction)				
Cost effectivenes s (US $ /t CO2 reduction)	119	115	173	176	1602	88	257	102	592	541

Incremental cost per kwh	Agro-wast	Wood-wa	Wind shal	Wind dee	PV pump	Small hyd	Wind farm	Biomass power		Photo Voltaic
(US $/ kwh)	-0.046	-0.036	0.054	0.044	1.354	0.47	-0.019	-0.12		0.28
Carbon dioxide reduction (Kg CO2/kwh)	0.5	0.5	0.5	0.5	0.5	1.3	1.3	1.6		1.6
Incremental cost effectivenes s (US $/kg CO2 reduction)	-0.092	-0.072	0.105	0.088	2.708	0.36	-0.02	-0.008		0.18
	-0.09	-0.07	0.11	0.09	2.71	0.36	-0.01	-0.08	#DIV/0!	0.18

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	Rs/KW	kg/ KWh	Rs/kWh	Rs/kwh (e	Rs/kg	$/KW	$/kwh Financial	$/kg	$/t of CO2	$/kwh Economic
S Hydro	35114	1.3	2.07	1.21	1.59	877.85	0.052	0.040	39.808	0.030
W Farm	25297	1.3	6.03	3.82	4.64	632.425	0.151	0.116	115.962	0.096
Biomass Power	12797	1.6	2.95	2.47	1.84	319.925	0.074	0.046	46.094	0.062
Solar Thermal	67151	1.3	13.87	11.93	10.67	1678.775	0.347	0.267	266.731	0.298
PV	107142	1.6	15.6	8.02	9.75	2678.55	0.390	0.244	243.750	0.200
						0	0.000	0.000	0.000	0.000
Gsifier-a	13690	1.6	3.45	2.38	2.16	342.25	0.086	0.054	53.906	0.059
Gasifier-w	12500	1.6	3.34	2.49	2.09	312.5	0.084	0.052	52.188	0.062
Wind-s	20833	1.6	4.99	2.76	3.12	520.825	0.125	0.078	77.969	0.069
Wind-d	38690	1.6	5.08	9.62	3.18	967.25	0.127	0.079	79.375	0.241
PV pump	154762	1.6	46.15	21.52	28.84	3869.05	1.154	0.721	721.094	0.538

	Rs/KW	kg/ KWh	Rs/kWh	Rs/kg	$/KW	$/kg	$/t of CO2	Incremental cost per	
						0	0		
S Hydro	35114	1.3	2.07	1.59	877.85	0.039808	39.80769	0.47	18.8
W Farm	25297	1.3	6.03	4.64	632.425	0.115962	115.9615	-0.019	-0.76
Biomass Power	12797	1.6	2.95	1.84	319.925	0.046094	46.09375	-0.12	-4.8
Solar Thermal	67151	1.3	13.87	10.67	1678.775	0.266731	266.7308		0
PV	107142	1.6	15.6	9.75	2678.55	0.24375	243.75	0.28	11.2
					0	0	0		
Gsifier-a	13690	1.6	3.45	2.16	342.25	0.053906	53.90625	-0.046	-1.84
Gasifier-w	12500	1.6	3.34	2.09	312.5	0.052188	52.1875	-0.036	-1.44
Wind-s	20833	1.6	4.99	3.12	520.825	0.077969	77.96875	0.054	2.16
Wind-d	38690	1.6	5.08	3.18	967.25	0.079375	79.375	0.044	1.76
PV pump	154762	1.6	46.15	28.84	3869.05	0.721094	721.0938	1.354	54.16



Map 1 Major power generating plants of the country

3 Power sector

Overview

India has an installed capacity of about 87 000 MW of which about 65 per cent is coal based. The country experiences an energy shortage of about 10 per cent and a peak power shortage of about 20 per cent. The demand for power has been growing at the rate of 9 per cent per year and is likely to accelerate further because of the economic liberalization policies of the Government of India.

It is estimated that the capacity required for installation will be over 12 000 MW every year over the next three Five Year Plans. The power demand in India by the year 2020 is estimated to be 385 000 MW, requiring about US$ 380 billion (TERI estimates) to be invested in the power sector alone. Coal would continue to be the dominant fuel for power generation in the country.

The costs of establishing power supply facilities and fuel inputs have also been increased over the years. Also, the efficiency of coal conversion in the Indian Thermal Power Stations (TPS) is low - average gross conversion efficiency being 28% and the average net efficiency about 25% (CEA 1990). Thus, option for increasing the efficiency in the power sector includes undertaking a renovation and modernization (R & M) programme. This is one of the important options that could be undertaken under AIJ.

Generating capacity[1]

The generating capacity of utilities comprises a mix of hydro, coal/oil/gas based thermal and nuclear plants. The installed capacity, which was about 1,700 MW in 1950/51 has grown to 81,000 MW by 1994/95 and presently is at 87000 MW. The annual rate of growth is about 9.5% during the period 1950-95. Up to mid 1960s, the thrust was more on developing hydel projects, but, since 1970s, the thermal capacity has shown remarkable increase and its share was 71% in 1994/95. The share of hydro power rose to 43% in 1970/71, but has been steadily declining and was about 26% in 1994/95. The share of hydro-capacity has been declining due to

1 The sub-section of this section on overview draw a lot upon TERI 1997b, Relative economics of fuels in power generation, submitted to HPCL and TOTAL SA

various reasons including adverse environmental impact and large scale displacement of population. The share of nuclear power has been almost stationery at about 3%. Table 2 gives the installed capacity and also the share in different periods. The share of coal based thermal in total thermal generation capacity was 91% in 1994/95.

Table 2 Installed generating capacity (Giggawatts)

Year	Utilities						Total
	Hydro	*%*	*Thermal*	*%*	*Nuclear*	*%*	Utilities
1950/51	1	35	1	65	-	0	2
1960/61	2	41	3	59	-	0	5
1970/71	6	43	8	54	1	3	15
1980/81	12	39	18	58	1	3	31
1990/91	19	28	46	69	2	3	67
1994/95	21	26	58	71	2	3	81
1995/96	21	25	60	72	2	3	83

Source.: Annual Report 1995/96, Ministry of Power, GoI

Power generation

The gross power generation from utilities has increased rapidly registering an average growth rate of about 10% per annum for the period 1950-95. The details of gross generation for different periods are given Table 3.

Table 3 Gross electricity generation (Billion kilo Watt hour)

Year	Hydro	%	Thermal #	%	Nuclear	%	Total generation
1950/51	3	49	3	51	-	-	6
1960/61	8	46	9	54	-	-	17
1970/71	25	45	28	51	2	4	55
1980/81	47	42	61	55	3	3	111
1990/91	72	27	187	71	6	2	264
1994/95	83	23	263	75	6	2	351
1995/96	73	19	299	79	8	2	380

Source: Economic Survey 1995/96

coal, diesel and gas

Energy and peak shortages

Despite significant achievements in capacity addition, the power sector has been plagued by serious shortages of supply vis-à-vis demand. The present shortages are mainly on account of growth in demand for power outstripping the growth in generating capacity addition and the serious financial resource constraints. At the commencement of the Eighth Plan (April 1992), the country faced peaking shortages of around 19 percent and energy shortage of about 8 percent. The position was much the same four years later: corresponding figures at the end of March 1996 were 18.3 percent and 9.2 percent respectively (Table 4). The situation may further aggravate, if the capacity needed for the foreseeable future does not materialize.

Table 4 India's power shortages (%)

Year	Energy shortage	Peak shortage
1990/91	7.9	15.5
1991/92	7.7	18.8
1992/93	8.3	20.5
1993/94	7.3	18.3
1994/95	7.1	16.5
1995/96	9.2	18.3

Source: Annual Report, Ministry of Power, GoI 1995/96

Mitigation options

In the power generation sector, the mitigation technologies which can emerge as attractive AIJ/CDM options have been identified and are listed in table 5.

Table 5 Operating efficiencies of power generation technologies

Technology	Operating efficiency (%)	
	Present	*Future*
Combined cycle plants	45-55	58-60
Integrated gasification combined cycle (IGCC)	38-40	45-47
Inter-cooled steam injected gas turbine (ISGT)	38-40	47-49
Pressurized fluidised bed combustion (PFBC)	37-40*	42-45
Pulverized coal super-critical boilers (PSCB)	40-42*	53-54

*Technology in commercial demonstration stage

Source: TERI 1997.

Besides these technologies, industrial cogeneration and diesel generation are also two options that can be considered as AIJ/CDM.

These GHG abatement options were analyzed in detail under the project undertaken by TERI (TERI 1997). The analysis is summarized below in Table 6.

Table 6 Cost benefit analysis of options for power generation

Technology	CO2 abatement (kg/kWh)	Economic cost (kg/kWh)	Financial cost (kg/kWh)
Cogeneration	1.5	0.27	0.07
Combined cycle	0.96	0.94	0.76
Inter-cooled steam injected gas turbine	0.79	1.03	0.91
Pressurized fluidized bed combustion	0.32	1.60	1.32
Integrated gasification combined cycle	0.28	1.40	1.15
Pulverized super critical boilers	0.23	1.09	0.92

Note : The values are in 1990 prices

Source: TERI, 1998. TERI Energy Data Directory & Yearbook (TEDDY), 1997-98, New Delhi

Combined Cycle Power Plants

Combined cycle power plants have both gas and steam turbines that supply power to the network. The waste heat from the gas turbine exhaust gases is recovered to generate steam in a waste heat recovery boiler; which is subsequently utilized for power generation by passing the steam through a steam turbine.

Scope of application

It has a capacity greater than 50 Mwe for utilities. The current maximum is about 880 Mwe. The fuels that could be used are natural gas, blast-furnace gas, methane, distillate oil, Naphtha, LSHS, residual fuel oil, methanol and coal derived gas.

Availability

Gaseous and liquid fuels – commercial
Direct-fired solid fuels - developmental.
There are a few GTCC plants in India.

Estimated benefits

The economic and financial benefits that will accrue are approximately over 50% savings in coal every year in over its life time. Financial benefits to the facility that will accrue are as per the Government of India's policy applicable to the power plants which include a 5 year tax holiday, further tax rebate of 30% after the 5 year period, accelerated depreciation and a minimum of 16% return on capital.

Constraints

Institutional: The MOP(Ministry of Power), Government of India, has now deregulated the power sector and has no restrictions on the technology for generation. However, there are concerns for the use of liquid and gaseous petro fuels for power generation for energy security reasons and preference is given to power generation by coal.

Other: The fuel for combined cycle power generation has to be imported, and is subjected to fluctuations in the international prices.

Technical: High efficiency new generation large gas turbines have to be imported, however the latest version are on test and will be available in 5 years time.

Diesel cogeneration

Diesel generators (DG) are used as standby power generating stations in India. These gensets are normally compression ignition engines. The exhaust temperatures of the exhaust gases are normally in the range of 400oC to 500oC and can be used for heat generation in waste heat boilers or for direct heat applications.

Scope of application

Has applications in electric power generation, shaft power, and steam generation. It has a typical size range of 3 to 30 MWe, and unit capacity of 5 kWe to 30 MWe. The capacity can be increased by pairing packages; but in remote locations, multiple units may present problems. The fuel required is: natural gas, propane, low-Btu gas, coal-derived gas, diesel, low-grade kerosene, crude oil, coal liquids, shale oil, residual oil, and vegetable oils.

Availability

Commercial for gaseous and liquid fuels

Developmental for coal-fired operations

Estimated benefits

The financial benefits to the facility are as per the Government of India's (GOI) policy for energy efficiency /energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal as well as oil used for steam raising. The savings in coal due to the adoption of cogeneration is 0.748 Kg/'000 tons of steam.

Constraints

Financial: Upfront costs are high.
Institutional: The DG set manufacturers are not waste heat recovery boiler manufacturers. Hence, the user has to procure a waste heat recovery boiler specially suitable for the DG set. The system has to be packaged suitably to meet the users need and hence is expensive.

Policy: A policy to have waste heat recovery systems for DG sets (above a certain capacity) needs to be specified.
Other: Most of the DG sets are operated as standby systems. Diesel based cogeneration will be economical only if the DG sets are operated for 3000 hours or more.

Industrial cogeneration

Cogeneration simultaneously generates electricity and thermal heat for process application or space heating. It can be used whenever on site electricity generation is required or thermal energy users are in close proximity. Its size depends on type of fuel used, power-to-heat ratio, and type of power cycle used.

Scope of application

Cogeneration is applicable in energy intensive industrial sectors like iron & steel, pulp & paper, cement, sugar, fertilizer, chemicals and petrochemicals and several others. Sugar industry is one of sub-sectors that offers the largest potential in India. The current cogeneration potential estimates range between 17,000 to 20,000 MW. However, the real potential will be larger and is yet to be determined.

It has a lifetime of upto 30 years for gas or steam turbines, and upto 6 years for Diesel engines. The ranges are as follows:
Steam turbines: extraction-condensing types of 30-300 MWe, and back-pressure type of 20-200 Mwe.

Potential of industrial cogeneration in India

Combustion gas turbines - 10 to 100 MWe.
Indirectly fired gas turbines: Open cycle - 10 to 85 MWe, Closed cycle - 5 to 350 Mwe.
Diesel engines 0.05 to 25 Mwe.

The fuels that can be used include coal, natural gas, fuel oil, biomass, industrial by-products.

Availability

Commercial.

Estimated benefits

The financial benefits to the facility are as per the Government of India's (GOI) policy for energy efficiency /energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal as well as oil. Because of its decentralized nature of power generation the societal benefits are significant such as reduced transmission and distribution (T&D) losses and low capital requirement per MW of power generation and in T&D.

Constraints

Financial: The capital investments in the cogeneration projects are high. The financial performance of most State Electricity Boards (SEBs) is very poor and hence the investors are reluctant to sell surplus power to the SEBs, under the current situation.

Institutional: The state electricity boards in most States do not have a firm policy on cogeneration. The issues related to banking and wheeling have still to be resolved including direct sales to third party. The purchase price of cogenerated power varies and most states prefer to pay the marginal costs of generation. The industry prefers to avoid making investments in cogeneration projects for export of surplus power to the grid because it has not paid the capacity charges.

Policy: There is no policy on cogeneration except for bagasse based cogeneration. The SEBs in most States have yet to formulate comprehensive policies on cogeneration.

Integrated gasification combined cycle (IGCC)

IGCC process uses coal with air and steam or oxygen and steam at high temperatures which causes the coal to gasify to a mixture of hydrogen, carbon monoxide, carbon dioxide and hydrogen sulfide etc.

Scope of application

It has a typical economic size range of 200 to 800 MWe capacity. Modular designs of 50 to 250 MWe are expected to be the basis for future IGCC power plants, with larger sizes provided by integrating multiple units. It can use any high hydrocarbon fuel including low and high sulfur coal, anthracite, and biomass.

Estimated benefits

The economic and financial benefits that will accrue are approximately 32% savings in coal, annually. Financial benefits to the facility that will accrue are as per the Government of India's policy, applicable to the power plants: 5 year tax holiday, further tax rebate of 30% after the 5 year period, accelerated depreciation and a minimum of 16% return on capital.

Constraints

Financial: The cost of the plant is comparable to that of coal fired normal thermal plants plus flue gas desulphurisation (FGD). But FGD is not used in Indian power stations as sulphur content in coals is low.

Institutional: The results of the analysis are not available. The infrastructure for the manufacture of gas turbines for the use of gasified coal and syngas do not currently exist in India.

Policy: No particular policy on the adoption of power generation is specified by the Ministry of Power, Government of India. However, use of coal is still the preferred fuel for reasons of energy security and foreign exchange implications.
Technical: Compatibility of the technology with Indian coals would need to be established.

ISTIG / STIG (inter-cooled steam injected gas turbine)

Steam/water is injected in the air from the compressor before it is fired and supplied to the combustor. This increases the efficiency of the turbine and also has low NOx emissions. The inter stage cooling of the compressor is carried out to achieve high compressor efficiency. This is a modification of the simple Brayton cycle.

Scope of application

Has a typical size of 50-150 MWe, and a capacity of 5 to 300 MWe (projected). It can use, as fuel, natural gas, blast-furnace gas, distillate oil, residual oil, coal-derived gas and biomass derived gas.

Availability

Commercial for gas turbines; prototype for intercooled, steam-injected, and solid fuels gasification systems.The turbines required for these applications are currently not manufactured in India. However, GEC-Alsthom has started marketing small size (2-8 MW) steam injected gas turbines in India.

Estimated benefits

The economic and financial benefits that will accrue are approximately 7-10% savings in gas turbines that use Brayton cycle every year in over its life time. Financial benefits to the facility that will accrue are as per the Government of India's policy, applicable to the power plants: 5 year tax holiday, further tax rebate of 30% after the 5 year period, accelerated depreciation and a minimum of 16% return on capital.

Constraints

Financial: The costs are slightly higher than the conventional gas turbines.
Other: The technology has to be imported.

Pressurized fluideized bed combustion (PFBC)

In the PFBC the mixture of crushed coal is mixed with limestone and suspended on the air jets. This bed of coal resembles that of a boiling liquid and hence the name fluidized. The pressures in the combustion chambers are about 6 to 16 times higher than is the Atmospheric Fluidised Bed Combustion (AFBC) where the combustion is at the atmospheric pressure.

Scope of application

The unit capacity is 50 to 250 MWe. Larger sizes are provided by integrating multiple units. It can use typically any high sulfur solid fuel including coal, anthracite and biomass.

Availability

Four development plants (2 in U.S., 1 in Spain and Sweden each) are currently under construction/operation. One 250 MW unit is under construction in Japan.

Estimated benefits

The economic and financial benefits that will accrue are approximately 7-10 % savings in coal consumed every year in over its life time. Financial benefits to the facility that will accrue are as per the Government of India's policy, applicable to the power plants: 5 year tax holiday, further tax rebate of 30% after the 5 year period, accelerated depreciation and a minimum of 16% return on capital.

Constraints

Financial: The upfront costs of the PFBC technology are high.
Institutional: The fluidized bed combustion technology is yet to be accepted among the Indian utilities. Even the AFBC technology, which are commercially available for industrial boilers is still to make a good impact in the Indian scenario.

Technical: Compatibility of the PFBC technology with the high ash Indian coals is yet to be established. The reliability of ceramic filters used for hot gas cleanup is yet to be established.

Pulverized coal super-critical boilers

The steam pressure and temperature in super critical boilers are extremely high. The operating pressure is greater than 260 kg/cm2 (g), compared can be over 600oC.

Scope of application

The unit capacity is 200 to 500 MWe.

Availability

Globally, this is a commercial technology. Currently, there is no such technology in India.

Estimated benefits

The economic and financial benefits that will accrue are approximately 7-10 % per savings in the coal consumed every year in over its life time. Financial benefits to the facility that will accrue are as per the Government of India's policy, applicable to the power plants: 5 year tax holiday, further tax rebate of 30% after the 5 year period, accelerated depreciation and a minimum of 16% return on capital.

Constraints

Financial: The cost of this power plant is approximately 15-20 percent higher than that of the sub-critical power plant boilers.
Institutional: Currently the super-critical pressure boilers and the turbines are not manufactured in India. The Central Electricity Authority (CEA) in India and the utilities have still to accept this technology.
Policy: The CEAs earlier policy was not to allow super-critical boilers. However, the current opinion is changing because of the increasing use of this technology the world over.

Other: The technology for supercritical boilers will have to be imported. However the technology for the steam turbine is avaiable in the country.

Transmission and distribution*

Amorphous core transformers

Distribution transformers are used in very large number in the power network and considerable energy is consumed in the form of core losses. It is estimated that over 1.5 million DT (distribution transformer) are already in service in India and about 150,000 transformers are added every year.

Amorphous metal cores consumes far less energy compared to silicon steel cores (presently used in transformers) and the reduction is as high as 70-75%†. The most attractive characteristic of the amorphous alloy is its extremely low core losses i.e 0.21 W/kg (at 1.4 Tesla) against the 0.9 W/kg of the CRGO silicon steel. Switching over from silicon steel to amorphous metal for purchase of new transformers will save about 200 million kWh‡ energy every year. By the year 2000, cumulatively, about 4500 million kWh of electricity costing over Rs. 1000 crores to the power utilities will have been saved.

Availability

Ministry of Power in 1994 launched through Rural Electrification Corporation, a pilot programme of installing 3000 amorphous metal transformers in selected States and also agreed to provide subsidy towards meeting the cost difference over the conventional silicon steel transformers. This programme has not only enthused the SEB,s in procuring amorphous transformers but also prompted major distribution transformer manufacturers to take up production of such transformers.

One of the important factors which has hastened the process of indigenous production of amorphous metal transformers in the country is the availability of amorphous metal cores from the US-based Allied Signal's joint venture plant in India (USHA amorphous Metals Ltd. Gurgaon). This makes it possible for the transformer

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* TERI 1997

† Source: Debut of ultra energy-efficient transformers in India. Mr G L Dua, former Director, Technical, REC. Paper presented in Transform 95 (ITMA)

‡ Source: Debut of ultra energy-efficient transformers in India. Mr G L Dua, former Director, Technical, REC. Paper presented in Transform 95 (ITMA)

manufacturers to take up commercial production of amorphous transformers with only small additional investments.

Costs

The cost of the amorphous core transformers are costlier by 20-25% than the traditional silicon steel core transformers whereas the core losses will be reduced to one-third in the amorphous core transformers. Assuming the cost of the silicon steel transformer be Rs 1000.00 per kVA. The cost of the amorphous core transformer would be Rs 1200 per kVA.

Total energy sold during the year 1993-94: 2.38 * 1011 kWh*
transformer core losses (2%) : 4.76 * 109 kWh

Core losses in amorphous core transformer: 1.58 * 109 kWh
Energy savings (annually): 3.17 * 109 kWh *2.7 = Rs 8.56 billion
Capacity savings (average): 528 MW * 4 *107 = Rs 21.13 billion
Total annual savings Rs 29.69 billion

Reduction in CO2 emission 3.17 * 109 * 0.71 * 44/12 = 8.25 * 109 kg

Total installed capacity of distribution transformers :
110567781 kVA

Total cost (assuming Rs 900.00 per kVA):
Rs 99.51 billion

Cost of amorphous core transformer (@ Rs 1000.0 per kVA
Rs 110.56 billion

Annualised cost 110.56 * 0.266 = 29.40 billion
(taking r = 0.15; tax rate = 0.43 and L = 30 years)

Constraints

(1) High capital cost

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* Source: CEA's General Review, 1993-94

(2) Current manufacturing capacity is limited

Cost (financial) of Amorphous transformers:
25 kVARs 25800.00
63 kVARs 45400.00
100 kVA Rs 59000.00

HVDC transmission

High voltage direct current (HVDC) transmission is used to transmit bulk power through long distances. Some of the major advantages of HVDC over AC transmission are:

- It requires only two conductors as compared to three for AC conductor.
- Expansion of 400 AC system is not possible in highly populated areas and dense forests in view of the constraints of right-of-way in limited transmission corridors in general and the problem of aligning transmission lines in forest areas in particular.
- There is no inductance, capacitance, phase displacement and surge problems in DC transmission.
- Due to the absence of inductance, the voltage drop in a DC transmission line is less than AC line for the same loading and sending end voltage.
- There is no skin effect in a DC system. Therefore, entire cross-section of the line conductor is utilized.
- For the same working voltage, the potential stress on the insulation is less in case of DC system than in AC system. Therefore, a DC line requires less insulation.
- A DC line has less corona loss and reduced interference with communication circuits.
- Reliability Criteria: One + 450 kV bipole is as reliable as two separated 400 kV AC lines.

The major disadvantage of DC system is the high terminal equipment cost.

Availability

The 1500 MW Rihand-Dadri + 500 kV bipole has been completed and is in operation since 1991. The length of this line is 910 kM. Another 1500 MW HVDC + 500 kV bipole between Chandrapur

and Padghe has also been approved and is under execution. Another scheme for providing HVDC interconnection between southern and eastern regions which has been techno-economically appraised by the CEA is under process for investment approval.

An operational study carried out by NREB to examine the effect of Rihand-Dadri line on the system performance has revealed that with one of the poles which is under trial operation, there is significant improvement in voltage levels at the various 400 kV substations in the northern region. With the generation level maintained the same, the EHV system losses reduces from 422 MW (4%) to 330 MW (3.2 %).

Cost and economic parameters

To compare the AC transmission system with the HVDC technology, the following points should be considered:

- cost of ohmic losses (energy and demand)
- load factor
- cost and procedure to evaluate corona losses
- cost of right-of-way
- interest rate
- life of different components
- annual maintenance and operational costs
- depreciation procedures
- reliability evaluations

A study carried out by CEA to transfer 2500 MW of power through a distance of 1000 kM from northeastern region to other regions of the country. The comparison of the costs with various technology options are given below:

Item	765 KVac	+ 600 kV HVDC	400 kV AC with series compensation
Investment (crores)	2500	3200	2700
Losses (MW)	100 (4%)	80 (3.2 %)	306 (12.24%)
Right-of-way (Fts)	367	152	256
Need for intermediate switching stations	Yes	No	Yes

From the above table, it is clear that though the initial cost of HVDC is high, it is compensated by low line losses.

Losses in 765 kV line = 100 MW equivalent to 4 billion (assuming 40 million per MW)

Losses in HVDC line = 80 MW equivalent to 3.2 billion
Losses in 400 kV a.c = 306 MW equivalent to 12.24 billion

400 kV AC is not cost effective. Comparing the 765 kV AC and HVDC transmission, though capital cost of HVDC is more by 7 billion, the peak demand is reduced by 20 MW.

Amount saved on account of capital cost = 20 * 4 * 107 = Rs 0.8 billion
Annualised cost (r =0.15, tr = 0.43, L =30) = 0.8*0.266= Rs 0.213 billion
Energy saved = 20 MW * 6000 hours = 120 million units
taking fuel cost = 53 paise/unit
Annual savings = Rs 63.6 million
Total savings = Rs 276.60 million
Additional cost incurred = Rs 7.0 billion
Annualised cost Rs 7.0 * 0.266 = Rs 1.86 billion

Energy saved = 120 mkWh
Reduction in CO_2 emission 120 * 106 * 0.71 * 44/12 = 3.12 * 108 kg

This calculation does not include the cost of the right-of-way, which is almost half in the case of HVDC transmission. Cost of right-of-way varies from site to site.

Constraints

- Technology has still to be stabilized
- High initial investment
- It is a point to point transfer of power, in-between tapping is very expensive.

Some project ideas

Some specific project ideas that could be developed as AIJ, as well as enhancing co-operation between India and Japan have emerged during the meetings and discussions with different industry groups and their representatives.

India is recognised as one of the large potential markets for energy in the coming years. The demand for electricity is growing at a rate of about 9% and with liberalization of the economy it is likely to continue to grow faster. So, there is a strong imperative to refurbish old plants and add new capacity. Therefore, in anticipation of increased energy consumption, developing country like India must be provided with clean coal technologies to minimise the undesirable effects of energy development. The policy of the Government of India is to make available electricity to the maximum number of people at the cheapest possible rate in an environmentally sustainable manner.

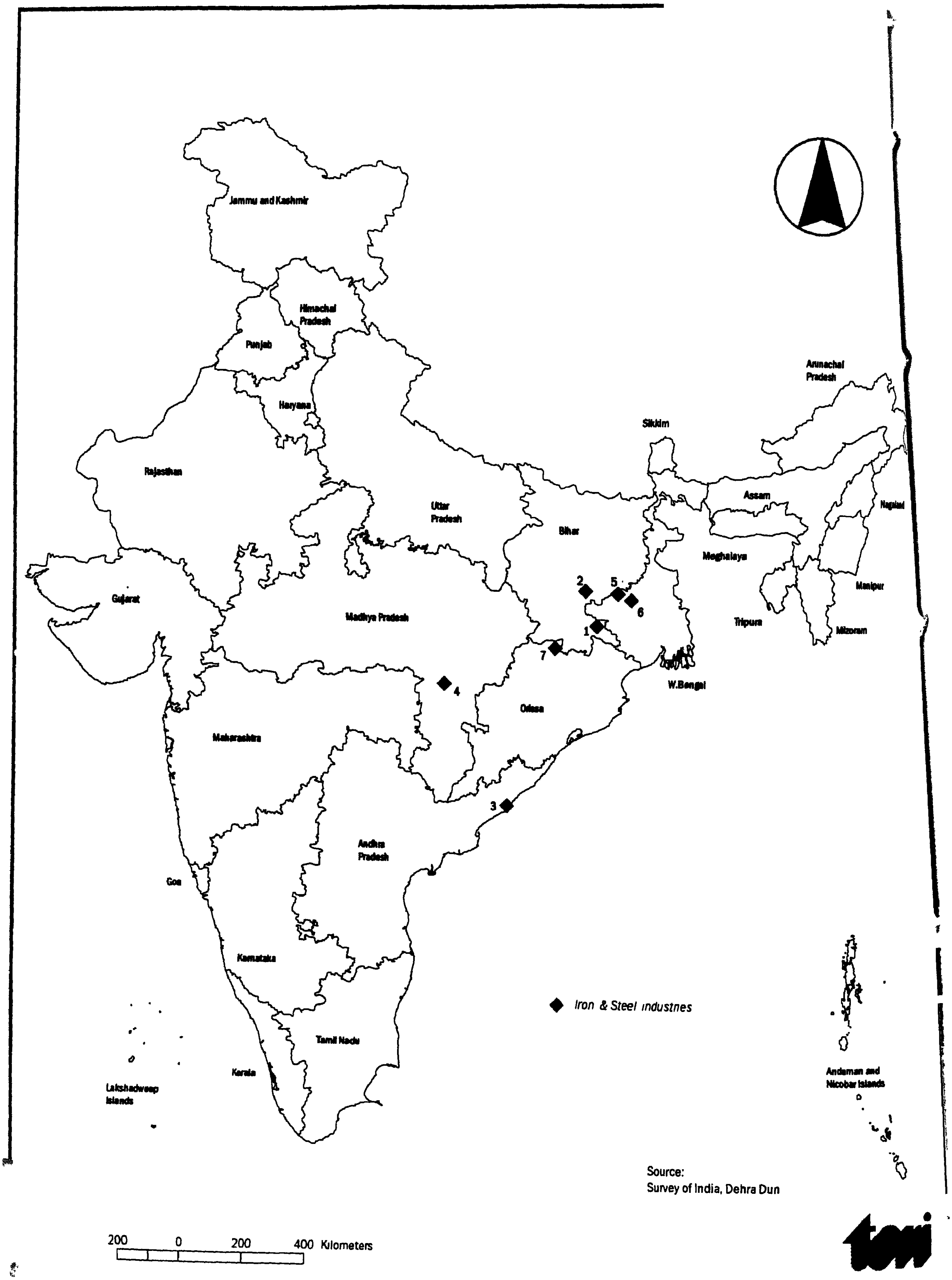
Given this scenario, there exists an enormous potential for introducing cleaner power generating technologies under the ambit of AIJ. Thus, any kind of financial assistance to infrastructure development would be of great importance. In the past also a Study Group on the Electric Power Development for India was established in July 1996 with the purpose of extending assistance for the development of power sector in India through the joint efforts between Japanese Government and private sector ("Japanese G/P Cooperation").

Three case studies have been provided for the power sector in India as ideas, which can be developed as AIJ projects between Japan and India. These are:

1. Replacement of the conventional pulverised coal sub critical technology by IGCC and PFBC systems.

2. Renovation and modernisation in the existing plants.

3. Bagasse based cogeneration.



Map 2. Geographic distribution of major Iron and Steel industries in India

4 Iron and steel sector

The iron and steel sector in India has been growing substantially over the years, particularly since after the delincencing of the steel industry 1991. With the increasing consumption of steel in the country, several new plants are coming up. Efforts are being made to improve the past performance and catch up with the changing technology, keeping in mind the quality and costs considerations.

Overview*

The iron and steel industry is the largest consumer of energy in the industrial sector. Energy cost constitutes 30% of the production expenditure of iron and steel. Two processes for production are in common use in India, namely, ISP (integrated steel plants), technically defined as the BF-OH/BOFs (blast furnace-open hearth/basic oxygen furnaces) and mini steel plant, scrap or sponge iron based EAFs (electric arc furnaces). There are seven integrated steel plants (ISPs) with a total capacity of 16.35 mt of crude(ingots) steel. These are the Tata Iron and Steel Co., the Durgapur Steel Plant, the Rourkela Steel Plant, the Bhilai Steel Plant, the Bokaro Steel Ltd., the Indian Iron and Steel Co., and the Vishakhapatnam Steel Plant. TISCO is in private sector while all others are in the public sector. India also has about 269 EAFs, with a total steel making capacity of 9.3 mt a year. Of these, as on March 1993, nearly 175 units were in operation, constituting an installed capacity of 7.3 mt.

India, however, has strong comparative advantages in steel with access to raw materials at relatively low costs and lower labour costs. The country also has an abundance of technical expertise and skilled manpower to help the domestic players have an edge over their overseas counterparts. This apart, the government has ushered in several policy changes to give a spurt to private sector investments in the steel industry.

Among the major changes are: removal of iron and steel from the list of industries reserved for the public sector; exemption of the iron and steel industry from provisions of compulsory licensing; its inclusion in the list of high priority industries for foreign investment; deregulation of pricing and distribution of iron and steel; reduction of duty on import of capital goods; and liberalization of the export-import policy. Around 8 million tonnes of capacity are being set up in the private sector with units like Loyds Steel and Nippon

* This section draws significantly from TERI's report prepared for UNIDO.

Denro in Maharashtra, Essar Gujarat in Gujarat, Jindal Strips in Madhya Pradesh and Malvika Steel in Uttar Pradesh firmly on track in their development plans.

The future of this industry definitely seems bright for the coming few years. With the recession in the industry coming to an end, there has been a surge in demand, coupled with rising prices of end products. Experts of this industry feel that the recession was a temporary aberration in the rising trend of this sector. The industry is expected to grow at an average rate of 10 percent in medium term according to an appraisal of the Credit Rating Information Services of India Ltd. (CRISIL). The massive investment in infrastructure, growth in transportation sector and increasing demand for consumer durables are the major propellants of demand for this industry.

The CRISIL study observes that the Integrated Plants will maintain their dominant positions on account of their depreciated units and lower costs. The Mini Plants continue to be under pressure because of an erosion of margins created by increasing raw material prices and power costs. The following table gives an idea of costs of production through various stages in different countries;

Table 7 Works cost of production through stages (in $/tonnes)

Production Stage	India	U.S.	Japan	Germany	U.K.	Australia	Korea	France	Brazil
BF	108	157	130	157	126	96	113	137	108
Liquid Steel	186	224	204	227	183	164	169	203	166
Slab	212	264	241	271	214	193	195	236	189
Hot rolled coil	276	343	319	366	278	261	241	308	238
Cold rolled coil	359	441	427	483	361	348	311	402	310

Source: Steel Scenario

Data pertains for the period February 1995

Demand

The demand in steel is projected to rise to 31 million tonnes by 2001-02. This is based on moderate estimates of growth of GDP (5% to 6% per annum). The potential for growth of the steel industry in India is borne out by the current low consumption figures. While India is producing about 18.5 million tonnes of crude steel annually, its per capita consumption is only 22 kg, which is among the lowest in the world.

Production

The total production of finished steel in the country in 1994-95 taking into account the primary and secondary sector was around 17.32 million tonnes. This

is expected to rise to 20.79 million tonnes in 1995-96. The following table gives production figures of finished steel over the last few years.

Table 8 Production of finished steel - All India (Million tones)

Producers	1990/91	1991/92	1992/93	1993/94	1994/95
A. Main Producers					
Bhilai Steel Plant	2.10	2.20	2.10	2.20	2.20
Bokaro Steel Plant	2.30	2.70	2.90	3.08	3.00
Durgapur Steel Plant	0.60	0.50	0.46	0.50	0.59
Rourkela Steel Plant	1.00	1.00	1.15	1.10	1.15
IISCO	0.24	0.32	0.32	0.25	0.28
Vizag	0.02	0.25	0.54	0.67	0.97
TISCO	0.93	0.99	0.94	0.97	1.37
Sub Total	7.19	7.96	8.41	8.77	9.56
B. Secondary Producers	6.34	6.37	6.79	6.46	8.26
Total	13.53	14.33	15.20	15.23	17.32

Source: Statistics for IRON & STEEL Industry in India, 1996

Table 9 Production of ingot steel (Million tones)

Producers	1990/91	1991/92	1992/93	1993/94	1994/95
Bhilai Steel Plant	3.50	3.74	3.90	4.00	4.00
Bokaro Steel Plant	2.80	3.42	3.60	3.70	3.70
Durgapur Steel Plant	0.90	8.71	0.70	0.60	0.90
Rourkela Steel Plant	1.30	1.23	1.30	1.40	1.20
IISCO	0.30	0.36	0.40	0.30	0.30
Vizag	0.10	0.58	0.10	0.10	0.10
TISCO	2.30	2.41	2.50	2.50	2.80
Total	11.20	20.45	12.50	12.60	13.00

Source: Statistics for IRON & STEEL Industry in India, 1996

Export

On the export side, against an export of 0.91 million tonnes valued at Rs 70.80 million during 1992-93, the exports in 1993-94 increased to 2.22 million tonnes valued at Rs 168 million showing an increase of 144 percent in quantity and 137 percent in value. However, 1994-95 witnessed a fall in exports due to increased domestic demand and reduced demand from China.

Specific energy consumption

In India, present levels of specific energy consumption are high in comparison to many other countries. For this, several reasons exists. Some of these are connected to the quality of ore, process of steel making itself, others are related to the structure of the sector, lower grade ores required more energy per tonne of pig iron output then high grade ores. Cokes are produced by making coal into evaporate volatile components. In fact, these components are recovered and used as fuel. Most ISPs in India still use the classical old wet quenching method for coke preparation. Dry coke quenching can be used instead of traditional quenching with water. It improves the coke quality, and reduces energy consumption and dust emissions. In India, awareness about reducing energy consumption has manifested itself only in the recent past. Although substantial energy conservation measures have been adopted in Indian ISPs, their performance leaves a lot to be desired when compared with their counterparts in other countries. Efforts are being made to reduce energy consumption further by importing good quality coking coal, developing heat energy recovery systems, phasing out the open hearth furnaces for steel-making and introducing more continuous casting.

Energy constitutes the single largest item of expenditure in the steel industry. Specific energy consumption (SEC i.e. average energy used per unit of physical output) in steel production plants in developing countries varies widely between countries. For some developing countries plants, it may be at a par with specific energy consumption in industrialized countries, whereas in other it is more than double. Country average values are given in table 10:

Table 10 Specific energy consumption in selected countries [GJ/ton crude steel] 1980[9]

Country	SEC	Country	SEC
OECD		Non-OECD	
France	23.9	Brazil	31.2[2]
Germany	21.8	China	38.1
Italy	17.1[1]	Mexico	26.0[2]
Japan	18.9	India	41.1
Portugal	31.4	Tunisia	22.3[2]
U.K.	19.3	Yugoslavia	31.4
U.S.A.	26.0[1]	Zimbabwe	19.3[2]

Source: [1] Data are from 1979

[2] Data are from 1990 [1-3]

This difference in SEC be caused by difference in technology and operational practices, maintenance, type of process, quality of ore and so on. Important

differences may, however, be due to differences in energy carriers used, structure of the sector and other local circumstances.

Table 11 Specific energy consumption (SEC) of integrated steel plants, India [GJ/ton crude steel]

	1990/91	1991/92	1992/93	1993/94	1994/95
A. Energy consumption					
BF Coke (dry) 10^3 Gkcal	68115	70339	71474	70597	73354
Petro fuel (10^3 Gkcal)	3288	3786	3318	2701	2820
Tar fuel (10^3 Gkcal)	2165	2227	2451	2221	2182
Gaseous fuel (10^3 Gkcal)	40046	43123	45645	44175	45477
Electricity (Operations) Million units	5189	8772	9847	7365	7744
10^3 Gkcal	4.46	7.54	8.47	6.33	6.65
Total energy consumption (10^3 Gkcal)	113618.46	119482.54	122896.46	119700.3	123839.6
B. Production of crude steel (thousand tones)	11271	12923	13641	13973	14893
C. Specific energy consumption					
In Gcal/ton	10.04	9.25	9.01	8.57	8.32
In GJ/ton	41.90	38.72	37.72	35.88	34.83

Source: Statistics for IRON & STEEL Industry in India, 1996

A few important GHG reduction technologies in the Iron and Steel sector are discussed in detail below:

Mitigation options

In the iron and steel industry the mitigation technologies which can emerge as attractive AIJ/CDM options have been identified and listed in table 12 below.

Table 12 Mitigation technologies in the iron and steel sector of India

Subsector/Technology	Base technology	Technology/process	Potential efficiency improvement (%)
Direct reduction process	Wet quenching + BF + OHF	Technology	32 (sp. Energy
Dry quenching + BF(HP) + TRT	Wet quenching + BF + OHF	Technology	19 (sp. Energy
Basic Oxygen Furnace	Open hearth furnace	Technology	80 (sp. Energy
Ultra high power - EAF	Conv. EAF	Technology	26 (sp. Energy
Continuous casting	Conv. Casting	Process	*

* Savings are of the order of 30 liters of oil/tonne of steel and 500-800 kWh/tonne of steel.

Source: TERI 1997.

The analysis for these technologies is given below (TERI, 1997):

Table 13 Cost benefit analysis of options in Iron & Steel Industry

Base technology	Mitigating technology/process	Financial cost	CO2 savings
Wet quenching+BF+OHF+RHF +Rolling	Director reduction process	Rs 8400-Rs 15,150 (US$230-415) per ton of finished steel at 1990 prices	457.615 Kg/tfs
Wet quenching+BF+OHF+RHF +Rolling	Dry quenching+BF(HP)+TRT+ BOF+CC	Rs 25,260-Rs 30,312 (US$692-830.5) per ton of finished steel without the TRT (top recovery turbine) in 1990 prices. The cost of the TRT in 1990 prices is 85-170 (23-4.7) million rupees (US$)	57.596 Kg/tfs
Open hearth furnance	Basic Oxygen Furnance	746-1493 (20.4-40.9) million rupees (US$) in 1990 prices	182.68 Kg/tonne of steel
Conv. EAF	Ultra High power	1555-1940 (42.6-53.2) million rupees (US$) in 1990 prices	1100.00 Kg/tonne of steel
Conv. Casting	Continuous casting	3500 (95.9) million rupees (US$) in 1990 prices.	1675.67 Kg/tonne of finished steel

Source: TERI, 1997

Manufacture of steel through direct reduction route

This technology is used in the manufacture of steel by direct reduction(DR) of iron ore to steel. The iron ore is directly reduced to iron by using coal or natural gas as a fuel. The product is known as sponge iron, which is then converted to steel in an electric arc furnace (EAF) adopting ultra high power furnace technology (UHF) and cast to the final product of finished steel. This is an alternative process to the integrated steel plants. The main technological components in the base case integrated steel plant is wet quenching(WQ), blast furnace(BF), open hearth furnace(OHF), reheating furnace(RH) and normal casting (NC).

Scope of application

The technology is applicable only in steel manufacturing using iron ore as the raw material.

Availability

Commercial

Potential for GHG mitigation

The table below gives the energy consumption at various stages of the process in the two technologies.

Technology	Electricity (Process) Kwh/ tfs	Electricity (Utilities) Kwh/ tfs	Electricity (Total) Kwh/ tfs	Heat *thousand Kcal/ tfs	Coking Coal/ tfs	Non Coking Coal/ tfs	Captive Power (% of operational Power)
Wet Quenching + BF(Normal) + OHF + RHF + Rolling	174	340	514	8176	1.054		43
Direct Reduction Furnace + EAF(UHP) + NC	730	75	805	453		0.614	nil

The specific energy consumption and the carbon dioxide abated is shown in the table 14 below:

	Specific energy consumption Gcal/tfs	Coking coal ton per tfs	Non coking coal ton/ tfs	Purchased Kwh, per tfs	CO2 emitted per Kg/ tfs	CO2 abated Kg/tfs
WQ+BF+OHF+RH+NC	7.893	0.948	0.223	344.000	3159.527	0.000
DR+UHF+RH+NC	5.384	0.000	0.860	730.248	2701.912	457.615

Estimated benefits

The major economic benefit is very low capital cost compared to the integrated steel plants which is approximately fifty percent lower than that of the integrated steel plants. The use of coking coal is eliminated as a reducing agent. Normal steam grade coal can be used be used for direct reduction of the iron ore to sponge iron which will substantially lower the operating costs. Natural gas can also be used as an alternative fuel in the direct reduction process.

Constraints

Financial: No financial constraints in the adoption of this technology.
Policy: There is no fixed policy on the type of technology to be adopted in steel-making process.
Other: This technology is not used for very large scale steel production. The capacity range for this type of technology is generally 0.2 - 1.0 million tons per year.

Dry quenching(DQ) of coke

This technology uses dry quenching (DQ) of coke produced in the coke ovens using nitrogen gas. The waste heat is then recovered from the hot nitrogen gas to generate power for internal use in the plant. In the iron-making process high pressure blast furnace(BF) is used in this process, which has a top recovery turbine(TRT). The blast furnace off-gases are expanded through the top recovery turbine to generate power for internal use in the plant and the remaining wasteheat is used for process heat application. The steel making process uses basic oxgen furnace (BOF) which uses oxygen for converting the pig iron to steel instead of fuel oil normally used in the open hearth furnace(OHF). The molten steel is then cast in a continuous caster(CC) to the relevant end products.

Scope of application

The technology is used in the manufacturing of steel primarily in the very large integrated steel plants where iron ore is the raw material. The normal capacities of such plants are equal or more than 3 million tons of finished steel per year.

Availability

Commercial

Potential for GHG mitigation

The table below compares the energy consumptions at each stage of manufacturing in the baseline technology and the suggested technology.

Technology	Electricity (Process) Kwh/ tfs	Electricity (Utilities) Kwh/ tfs	Electricity (Total) Kwh/ tfs	Heat *thousand Kcal/ tfs	Coking Coal/ tfs	Captive Power (% of operational Power) includes cogeneration
Wet Quenching + BF(Normal) + OHF + RHF + Rolling	174	340	514	8176	1.054	43
Dry Quenching + BF(Hi Pressure + TRT) +BOF + CC	247	790	1037	6278	0.963	103

The table below gives the specific energy consumption of the two technologies the base case technology and the suggested technology. The table also indicates the various forms of energy consumed in the technology and the extent of purchased power from the grid. The carbon dioxide abated is also indicated in the table 15 below.

	Specific energy consumption Gcal/tfs	Coking coal ton per tfs	Non coking coal ton/ tfs	Purchased Kwh, per tfs	CO2 emitted per Kg/ tfs	CO2 abated Kg/tfs
WQ+BF+OHF+RH+NC	7.893	0.948	0.223	344.000	3159.527	0.000
DQ+BF(trt)+BOF+CC	6.387	0.828	0.633	30.000	3101.932	57.596

Estimated benefits

There are significant benefits due to its inherent nature of the technology which adopts heat recovery at every stage and also purchase of power from the grid is significantly reduced. The cost of this technology is comparable to the normal BF-OHF route. The finished products are available directly without the intermediate stage of producing crude steel and reheating and finishing which is the normal practice.

Constraints

Financial: The cost of this technology are comparable with that of the normal steel making process using wet quenching, normal blast furnace, open hearth furnace route steel manufacture.is much higher than the cost of the normal

blast furnace route. The costs are in the range of 1700-2000 US $ per ton of finished steel as per the the World Bank Technical Paper No. 22 titled `Energy Efficiency in the Steel Industry with Emphasis on Developing Countries' published in 1984. There are no financial barriers if the technology is adopted for a greenfield project. However, retrofitting will prove to be extremely expensive.

Institutional: Most of the existing steel making capacity in the country is with the SAIL plants where the status of technologies is not state-of -the-art. SAIL has developed its own modernization plan to suit its requirements.

Policy: There is no fixed policy on the type of technology to be adopted in steel-making process.

Other: Technology needs to be imported. The adoption of this technology will require imported coking coal as not enough of the indigenous coal is of steel grade.

BOF (Basic oxygen furnace)

The technology is used in the manufacturing of steel from hot metal without using fuels. Hot metal from the blast furnace is converted directly to steel by blowing oxygen into the hot metal thus reducing the carbon content in the hot metal to below 1% and converting it to steel.

Scope of application

The technology is applicable only in steel manufacturing in integrated steel plants.

Availability

This is commercial technology but not available in India

Estimated benefits

The financial benefits to the facility are as per the GOI's policy for energy efficiency / energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal as well as oil. Almost all the energy used here is fuel oil hence significant savings in foreign exchange.

Constraints

Financial : Extremely high financial costs when compared with the traditional steel making using open-hearth furnace.

Institutional : Most old plants continue to use the old open-hearth furnace.

Policy : There is no fixed policy on the type of technology to be adopted in steel-making process. However, the Steel sector is now de-licensed and several steel plants are now being set-up in the country. It would appropriate to give financial incentives to the industries for the adoption BOF technology as against the OHF technology.
Other : Technology needs to be imported.

UHP-EAF(ultra high power - electric arc furnace)

The electric arc furnace is used for melting and refining of metals. Very large electric arc furnaces are used mainly in steel plants of capacitites greaters than 40 tons per charge. The principle of electric arc heating is that when electric circuit is interrupted (by air gap), current will continue to flow if the current is high enough to vaporize some of the conductor and thus fill the gap with a conducting vapor path. The electric arc furnace is capable of operating at temperatures up to the order of 3500^{0} C.

Scope of application

The technology is used in the manufacturing of steel primarily in the sponge iron plants and the mini steel plants that use only scrap as feed stock. However, there are other applications of the EAF is in abrasive, refractory, and electrochemical industries.

Availability

Commercial.

Estimated benefits

The financial benefits to the facility are as per the GOI's policy for energy efficiency /energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal.

Contraints

Financial : Extremely high financial costs when compared with the normal EAF steel. Retrofitting is extremely expensive.
Institutional : Most mini steel plants that are scrap based have low powered EAF and are inefficient because the furnaces have a sub-optimal capacity. UHP-EAF can be used only for charge sizes greater than 50 tonnes. The steel-making practice in India will have to change substantially.

Policy : There is no fixed policy on the type of technology to be adopted in the steel-making process.
Other : There is no fixed policy on the type of technology to be adopted in the steel-making process.

Technology needs to be imported. High electric intensity and requires very quality power supply.

Continuous casting

The technology is used in the manufacturing of steel. Molten steel is directly cast to finished steel totally by passing the intermediate stage of crude steel manufacture where substantial quantum of energy is wasted in the finishing.

Scope of application

The technology is applicable in steel manufacturing in both the integrated steel plants and mini steel plants.

Availability

Commercial.

Estimated benefits

The financial benefits to the facility are as per the GOI's policy for energy efficiency / energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal and oil. Continuous casting eliminates the use of re-heating and finishing.

Constraints

Financial : Extremely high financial costs when compared with the traditional steel making using open hearth furnace.
Institutional : Most old plants continue to use the old open hearth furnace.
Policy : There is no fixed policy on the type of technology to be adopted in steel-making process.
Other : Technology needs to be imported.

Some project ideas

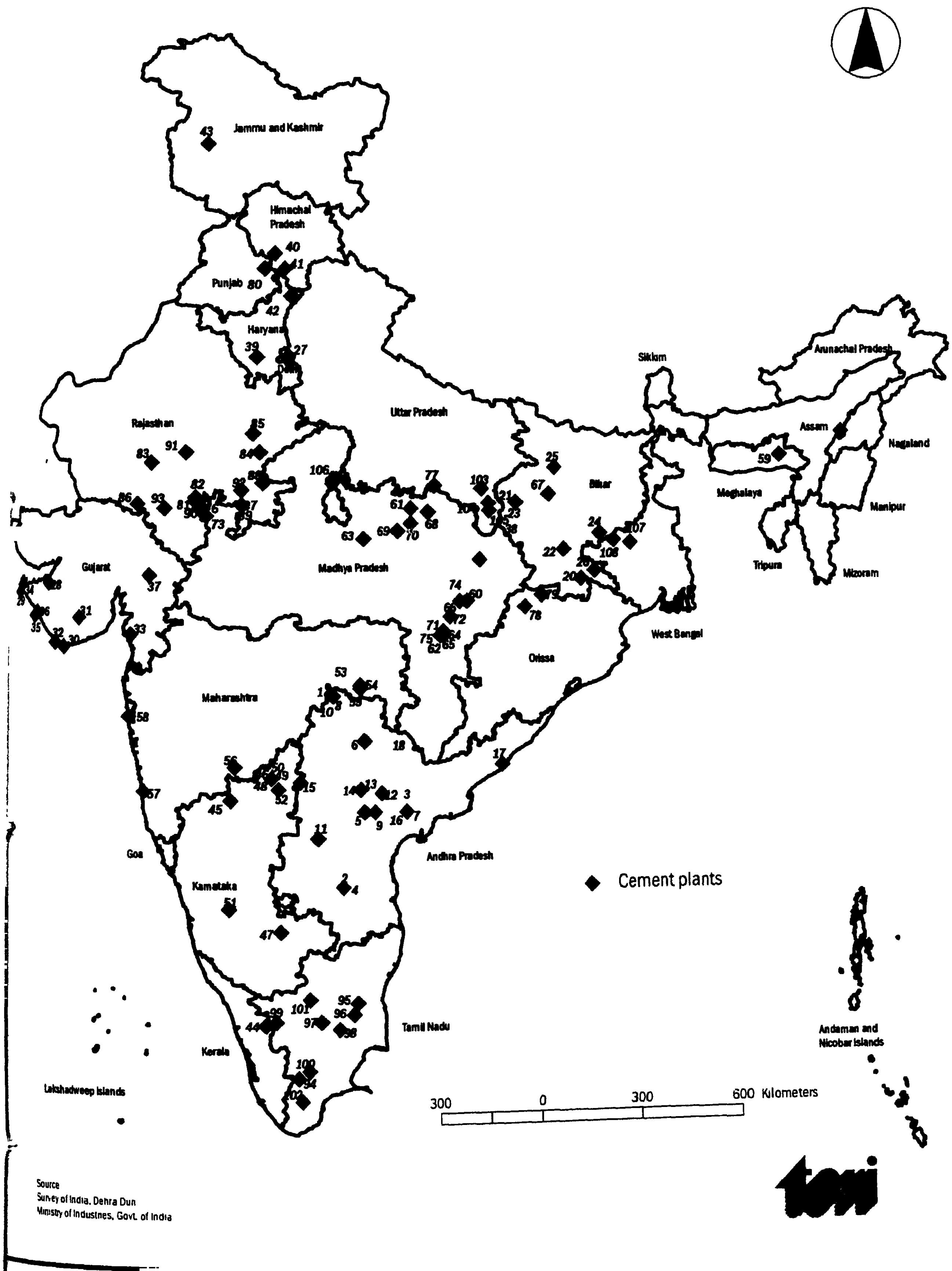
Some specific project ideas that could be developed as AIJ, as well as enhancing co-operation between India and Japan have emerged during the meetings and discussions with different industry groups and their representatives.

The Japanese steel makers have advanced energy saving technologies and have been extending technical assistance to their foreign counterparts. It is foreseen that the Voluntary Action Program for Environmental Steel-makers of the Japan Iron and Steel Federation, the manufacturers would be contributing to international technical co-operation through AIJ route as well.

One of the projects approved under the Japanese AIJ program is the waste-heat recovery investment project at a steel heating furnace at the plant of the Siam Iron & Steel Company Limited. The plant is located at Saraburi (near Bangkok) in Thailand. It aims at improving the efficiency of a recuberator to recover sensible heat from heating the furnace to preheat air for combustion. Control systems will be installed to adequately control the combustion when heating the furnace. The energy conservation is estimated to be about 1,000 tons of crude oil per year, and the corresponding CO_2 savings would be 3,100 tons per year (JIQ June 1998).

Some projects ideas that emerged for which immense interest was specifically expressed during our discussions and meeting with concerned industries and corporate houses, include:

1. Cogeneration: in the steel plants
2. Direct reduction of iron ore
3. Concersion of OHF to BF

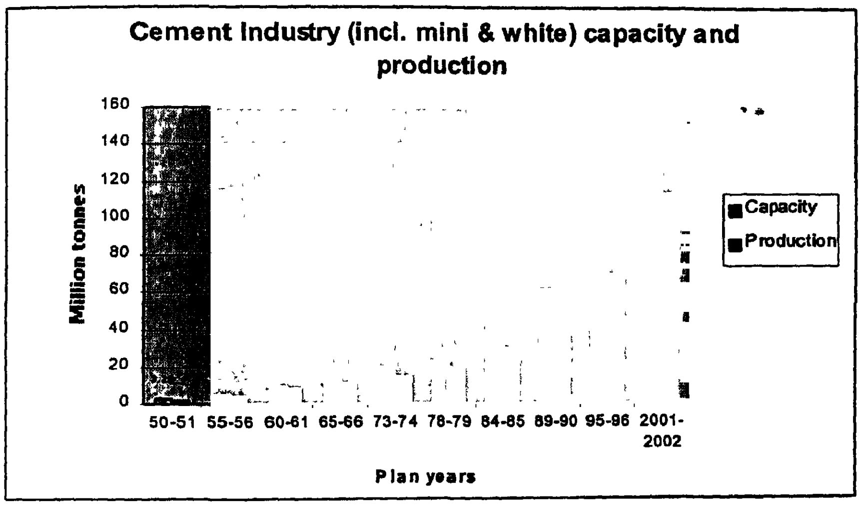


Map 3. Geographic distribution of Cement plants

5 Cement sector

Overview

India is the fourth largest producer of cement after China, Japan and the USA. The capacity and the production of cement in India has been increasing over the years (as seen in the graph). A brief profile of Indian cement industry is provided in Table 16.



Note : Figures for 2001-02 are based on projections.

Source: Cement manufacturer's Association, 1996, Indian Cement Industry (Statistics) 1995-96, New Delhi

Table 16 Profile of Indian Cement Industry

Cement plants (number)	115**
Plants with capacity of 1 million ton & above (number)	46
Installed capacity (million tons)	96
Cement production (million tons)	70 (1996-'97)
Capacity utilization (%)	81
Share of dry process plants (% of total plants)	82 (1992-'93)
Average specific thermal energy consumption	856 (1992-'93)
Average specific thermal energy consumption	1420 (1992-'93)
Average specific electrical energy consumption (KWh/ton of cement) - Dry process	122 (1992-'93)
Average specific electrical energy consumption (KWh/ton of cement) - Wet process	109 (1992-'93)

* Figures correspond to 1997, if otherwise not mentioned.
** Corresponds to the large plants only.

The cement industry is one of the six major energy intensive industries in India. Cement production involves the chemical combination of calcium carbonate (limestone), silica, alumina, iron ore, and small amounts of other materials and

is highly energy intensive. The specific energy consumption in cement production is in the range of 0.816 to 1.017 Gcal/ton. Though this specific energy consumption is relatively low compared to that in other energy intensive industries, the large volume of production involved makes cement one of the major total energy consuming industry in India.

Cement is manufactured in India using dry, semi-dry, or wet process (table 11). While in 1960 the dominating manufacturing process in India was wet process (94.4% of annual capacity), last two decades saw a significant shift towards dry manufacturing process. In 1995-96, dry process plants accounted for 87% of the industry's production. This was mainly due to the relatively lower thermal energy consumption of dry process in comparison to the wet process. However, the electric energy consumption of wet process is lower than that of dry process.

Table 17 Process wise production of cement (1995-96)

Process	Cement production (million tonnes)	%age to total
Dry process	56.09	87.0
Wet process	5.01	7.8
Semi dry process	0.58	0.9
Others	2.79	4.3
Total	64.47	100.0

Source: Cement manufacturer's Association, 1996, Indian Cement Industry (Statistics) 1995-96, New Delhi

Cement industry is a continuos process industry. Frequent power cuts or tripping damages the equipment besides causing a loss in the production. In order to maintain uninterrupted cement production, use of captive power by cement industry is increasing. New cement plants are including captive power plants in the project itself as part of the equipment. Table 18 shows the cement production obtained by the use of captive power.

Table 18 Cement production obtained by use of captive power

Year	Units produced by captive sets	Cement production from captive power	Percentage of cement production by use of captive power (%)
1990/91	930.14	7.75	16.94
1991/92	1166.30	9.72	19.20
1992/93	1100.00	9.17	18.08
1993/94	1248.65	10.41	19.25
1994/95	1481.18	12.34	21.15
1995/96	2109.06	17.58	27.24
1996/97 (P)	2346.49	19.55	27.94

Source : Cement Manufacturer's Association, 1997, 36th Annual Report 1996-97, New Delhi.

In 1994, Bureau of Industrial Costs and Prices (BICP) has brought out an energy audit report on the cement industry in India. The report has identified the potential energy savings possible by comparing the energy consumption of various plants against certain performance standards. Table 19 shows the energy savings projected by the BICP report and the corresponding savings in CO2 emissions that are possible. It is clear from the table that enormous scope for energy conservation and hence CO2 emission abatement exits in the Indian cement sector. The main barriers for realizing these potential savings have been identified as non-availability of technological and financial resources. Clearly this implies that one could consider the AIJ/CDM route in the cement sector for technology and resource transfer.

Table 19 Potential savings in energy consumption & CO_2 emissions in cement sector

	Energy Savings*		Savings in CO_2 Emissions (million tons)
	Thermal (million Gcal)	Electrical (million Kwh)	
Saving potential w.r.t. process-wise best performing Indian Plant	2253	586	1.5
Saving potential w.r.t. best performing Dry *Process Indian Plant*	3956	596	2.2
Saving potential w.r.t. International Practice (Dry process)	8483	718	4.0

*Source: Energy Audit of Cement Industry, BICP, 1994

Mitigation options

A number of technologies exist in various sub-processes of cement manufacturing for energy conservation and hence CO_2 emission abatement. Some of the important ones are listed below.

- Use of precalcinator in the dry process plants; expected to reduce the thermal energy requirement by about 1.72 GJ/ton of cement
- Addition of 5/6-stage preheater to utilize the exit gas temperature; expected to reduces the thermal energy requirement by about 1.53 GJ/ton of cement
- Co-generation in large dry process plants. A one million tons per annum cement plant is expected to avoid nearly 0.9 million tons of CO_2 emissions during its entire life time of 25 years (say) if it adopts waste heat recovery system
- Use of vertical roller mills, high pressure grinding rolls in cement grinding process
- Use of gyratory and mobile crushers in the raw material crushing process

Along with the energy conservation measures outlined above, other CO_2 emission abatement options include use of raw material with low carbon content.

The two major mitigation technologies are as follows:

Table 20 Mitigation options in the Cement Industry

Mitigation Process	Base technology	Potential efficiency improvement (%)
Dry precalciner kilns	non-precalciner kilns	30-40 (thermal energy)
Dry-suspension preheater kilns	non-preheater kilns	25-30 (thermal energy)

Source: TERI 1997

The analysis for these technologies is as follows (TERI 1997):

Table 21 Cost benefits analysis of the options of cement industry

Base technology	Mitigating technology/process	Financial cost	CO2 savings
Non-precalciner kilns	Dry precalciner kilns	Rs 1071-1190 per tonne of cement manufactured	218.42 Kg/tonne of cement
Non-preheater kilns	Dry-suspension preheater kilns	6 (0.16) million rupees (US$) per stage, at 1990 prices. Normally these are 5 to 6 stages in a state of the art plant	194.13 Kg/tonne of cement

Note: The figures are for 1990 prices.

Source : TERI, 1997

Dry precalciner kilns

Precalcination is a process of treating the raw meal before feeding it to the main kiln. In the precalcination process the pre-heated raw meal is heated at a lower temperature than that in the main kiln. In the precalcinator the amount of calcination achieved is approximately 85%–90% .

Scope of application

The technology is applicable only in dry process cement manufacturing.

Availability

This is commercial.

Estimated benefits

The financial benefits include those that are applicable under the Government Of India's policy package for energy efficiency /energy conservation technologies. This includes 100 per cent depreciation in the first year. The other significant benefit is that the facility will enhance the output of the cement plant by approximately 80%–90%. There are significant national benefits to be gained by adopting this technology primarily in terms of conservation of coal.

Constraints

Financial: The upfront costs are high when compared with the cement plants without precalciner. This as high as 1.5-2 times the cost of the normal plant.
Institutional: The cement market is now completely deregulated. The new entrants in the field generally adopt state-of-the-art technology and have international size scales over 1.00 million tonnes per annum. However, for smaller plants, the adoption of pre-calciner kilns and a computer-controlled system for the plant will generally not be financially attractive.

Dry-suspension pre-heater kilns

The hot gases leaving the main kiln are in the temperature range of about 900–1100°C and carry a substantial quantity of waste heat. This waste heat is recovered in the high efficiency suspension cyclone preheaters.

Scope of application

The technology is applicable only in the dry process cement manufacturing.

Availability

Commercial

Estimated benefits.

The financial benefits to the facility are as per the GOI's policy for energy efficiency / energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. However, the payback period is generally less than 2 years.There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal.

Constraints

Financial: Extremely high financial costs when compared with the cement plants without precalciner.

Institutional : The cement market is now completely deregulated. The new enterants in the field generally adopt state-of-the-art technology and have international size scales over 1.00 million tons per annum. However, for smaller plants the adoption of suspension preheater kilns and computer control system for the plant will generally not be financially attractive.

Cross-cutting technologies

Other than the specific technologies described in the sections above, there are a number of technologies which increase energy efficiency in the Industrial sector in India and are applicable to the iron and steel and the cement sectors as well.

Table 22 Cross-cutting mitigation options in the industrial sector

Technology	Base technology	Technology/process	Potential efficiency improvement (%)
Diesel cogeneration	Captive power generation using diesel generating sets	Technology	85-90@
Industrial cogeneration	No cogeneration	Technology	80-85@
Heat pump	No heat pump	Process	25-50 (thermal energy)
High efficiency motors	Conv. Motors	Process	3-8 (electrical energy)
Waste heat recovery systems	Systems without heat recovery systems	Technology	25-30 (thermal energy)
Low excess air high efficiency burners	Conv. Burners	Process	30-50 (thermal energy)

Source : TERI, 1997

Sorption heat pump

Sorption heat pumps in heating mode act as a heat transformer, which upgrade low-grade heat to high-grade heat (even low-pressure steam) which could be used for process heating to reduce primary fuel consumption. Liquids having low vapour pressure are normally used as working fluids in such units, are converted to high pressure high temperature fluid which rejects heat to heat sink. External fluid is used to remove that heat to generate low-pressure steam or hot fluid.

Scope of application

This is applicable in different process industries where continuous process heat is required. Essentially it will be applicable to upgrade low-grade waste heat to high quality heat without using any primary energy like coal, oil or gas.

Availability

These kind of sorption heat transformer is widely available in abroad. Thermax Ltd. and Voltas Ltd. are the two leading manufacturers of steam and hot water fired sorption heat pumps for cooling application in India. Conversion of these units for heating application will increase capital cost of these units by 15-20 percents.

Potential for GHG mitigation

17-35% of primary fuels for every kg of steam generated may be saved by using this technology. The carbon dioxide abated very depending on the fuel used for steam generation.

Estimated Cost

At 1990 prices the cost of the system would be in the range of 5952 to Rs 7143 per kw_{th}

Estimated benefits

Substantial reduction in the consumption of primary energy sources like coal, oil and natural gas in energy intensive process industries.

Constraints

Financial: Increasing cost of conventional fuel as well as electricity.
Institutional: Manufacturing companies monopoly as well as improper marketing strategy. No reliable indigenous technology is available as of today.
Policy: There exits no policy on waste heat recovery under the ministry of power.
Others: Subsidized primary fuel for such energy intensive industry like process industry and high capital cost of such sorption heat pump due to lack of reliable indigenous technology.

Efficient Electric Motors

The efficient electric motors have higher efficiencies, which can be obtained by incorporating design improvements to reduce intrinsic motor losses. These motors have a greater content of active material, use superior quality material

and require closer tolerances in machining and manufacturing operations. Its typical size is the same as that of standard motors.

Scope of application

Have applications in appliance and equipment power. Its major end use is in residential and commercial buildings. Motors comprise 60-70% of the total industrial load. So, using motors with higher efficiencies could save substantial amount of electricity.

Availability

Energy-efficient motors are commercially available in India for 3-phase applications from about 1 kW output through several hundred kW; some single-phase motors are available for certain applications.

Potential for GHG mitigation

The savings in energy will depend greatly on the size, application and the number of hours used per year. Gross estimates indicate about 2% savings in energy consumptions. The carbon emissions abated will depend on the KWh saved. The emission factor for end use efficiency is 1.6 Kg of carbon dioxide per KWh saved.

Estimated costs

Output		Cost of Standard Motor (Rs.)	Cost/KW of Standard Motor (Rs./KW)	Cost of Energy Efficient Motor (Rs.)	Cost/KW of EEMs (Rs./KW)	HP	Average Nominal Efficiency of Std. Motor %	Average Nominal Efficiency of Std. Motor %
KWw	HP					5	82	87
9.3	12.5	17534	1885	21032	2262	7.5	84	88
11	15	20669	1879	22165	2015	10	85	89
13	17.5	21285	1637	23342	1796	15	86	90
15	20	22990	1533	27588	1839	20	87.5	90.5
		Normative cost	1737	Normative cost	1978	25	88	91.5

Source : TERI, 1997

Estimated benefits

The total connected load of the industrial sector for the year 1993/94 was about 24,404,325 KW and the energy consumed was 61,427 million kWh. It is assumed that nearly 60-70% of industrial load is comprised by motors (both standard and energy efficient motor). The following table furnishes the energy saved by replacing standard motors with efficient ones. For the base case we have assumed that there are already 10% energy efficient motors and various other scenarios are given in Table 22.

	Base case (10% EEM + 90%Std)	Scenario-I (40%EEM + 60% Std)	Scenario-II (80%EEM + 20%Std)	Scenario-III (90%EEM + 10%Std)
Energy Consumed (MKwh)	61427	61058	60567	60444
Energy savings (Mkwh) @assuming 2%		369	860	983
Amount in Rs.(million) saved assuming tariff @Rs. 2.90		110	260	290
Amount invested to save this much of energy (million rs)		70	410	470

Constraints

Financial: Industries expect much higher rate of return for making investments in high efficiency motors.

Waste heat recovery from high temperature gases by the adoption of recuperators

Several industrial sectors like ceramics, glass, steel, fertilizers, petrochemicals and chemical industries and other metallurgical industries have high temperature waste heat ranging from 250 - 1100 degrees Celsius. These high temperature streams are a source of energy that can be used in the process. Recuperative heat exchangers are normally used to recover waste heat from the hot streams.

An example considered here for demonstrating the reduction in oil consumption and carbon dioxide abatement is waste heat recovery from reheating furnaces used in mini as well as large steel plants. The steel billets are

heated to about 1250 degree centigrade in a reheating furnace before the billets are shaped and finished to the end product. Most steel plants use furnace oil to heat the billets. The flue gas emerging from the furnace is in the temperature range of 900 - 1100 degrees centigrade. Most of the mini steel plants use reheating furnaces in the country. There approximately 275 mini steel plants in the country which cater to approximately 25 % of the steel manufactured in the country.

Scope of application

The technology is applicable only in several industrial sectors ceramics, glass, steel, fertilizers, petrochemicals and chemical industries and other metalurgical industries. Casting is not used.

Availability

Commercial

Potential for GHG mitigation

The energy consumption in the reheating furnace reduces approximately by 33 %. The carbon abated is 12 kg per ton of finished steel and the carbon dioxide abated is 44 kg per ton of steel finished.

In other sectors the potential for abatement would depend on the temperature of wasteheat stream and the savings potential will range from 10% to 40%.

Estimated costs

The cost of the recuperator ranges between Rs 9 to 25 lacs at 1994 prices depending upon the size of the reheating furnace and material of construction of the recuperator. The price of the recuperator at 1990 prices ranges between Rs 6 to15.5 lacs. These costs are based on verbal comunications from the L&T and Thermax Ltd.

Estimated benefits

The major financial benefit is that in most cases the payback is 2- 3 years depending upon the fuel used and the hours of operation is an year. For industrial units using fuel oil and other petro products as fuel there will be significant savings in the foreign exchange to the nation.

Constraints

The primary reason for not adopting this technology lack of information in the mini steel sector. In other sectors too this is the primary reason. However, there are other problems like scaling of the recuperators which calls for frequent cleaning. Corrosive nature of gases when the flue gas temperature falls below the

due point of SO2 and SO3 is another reason. This aspect calls for proper attention during operation of the plant.

Technology needs to be imported.

Low excess air high efficiency burners

Burners are used to release heat in combustion chambers in boilers and furnaces. The quantity of excess air required for complete combustion of the fuel is generally between 25 to 35 percent over and above the stiochiometric requirements. In low excess air high efficiency burners the combustion is achieved only by the use of 6-12 percent excess air.

Scope of application

The technology is applicable in all combustion processes which include boilers, furnaces, cement kilns, etc.

Availability

Commercial

Potential for GHG abatement

The stack losses in all combustion processes will reduce by approximately 30-50 percent from the current levels of loss.

Estimated costs

The cost of these burners varies between Rs 7 - Rs 25 lacs (1996 Indian quotes) depending upon the heat release rate.

Estimated benefits

The financial benefits to the facility are as per the GOI's policy for energy efficiency / energy conservation technologies. The facility will be eligible for 100 percent depreciation in the first year. There are significant national benefits by the adoption of this technology primarily in terms of resources conservation in coal and oil.

Constraints

Financial : Extremely high financial costs when compared with the normal burners. This as high as 3-6 times the cost of normal burners .

Institutional : All boiler, furnace and Kiln manufactures must adopt low excess air high efficiency burners. This has implications in the engineering and in the construction of the furnace and material of construction. High precision

engineering is required to manufacture high efficiency and low excess air burners.

Other : Technology needs to be imported.

Some project ideas

Some specific project ideas that could be developed as AIJ, as well as enhancing co-operation between India and Japan have emerged during the meetings and discussions with different industry groups and their representatives.

Some project ideas that emerged for which interest was specifically expressed during the meetings and discussions with different industry groups and their representatives, include:

1. Cogeneration: Power generation from waste heat in cement production process.
2. Alternative raw material for the cement industry: A technology is being developed in India to prepare an alternate material which has exactly the same properties as cement but is made using low grade and environment friendly material limestone instead of commonly using high grade limestone.
3. Carbon dioxide utilisation projects: The CO_2 that is emitted during the production of cement can be utilised for preparing methanol.
4. Reforrestation/afforestation of mines.

A case study on adoption of precalcinator in dry process cement plants has been provided in this report.

6 Future action

Recommendations for developing AIJ/CDM projects in India

The stand of Government of India on the AIJ projects is yet not clear. However, with regard to AIJ (without credits), as of now the government has taken an encouraging position and is seeking proposals for approval.

There has been a lack of awareness in the Indian industries and the corporate sector about the opportunities existing under AIJ/CDM. However, the situation is now improving substantially. TREAT in particular has undertaken the task of information dissemination and awareness creation. Many industrial houses are now coming up with innovative ideas.

Identification of projects

There are a lot of options for mitigation GHG emissions in India. However, the AIJ projects identified to be implemented in India should be such that:

- bring greener & cleaner additional funds and technologies in the country
- are in line with the development needs and priorities of the country
- bring about long term environmental benefits
- have learning experience benefits

We feel that the national criteria developed to identify and select projects should include the following:

- *Compatibility to national priorities, interests & policies*: This would mean looking at the major priorities as well as indirect benefits like leading to employment generation and bridging the energy demand-supply gap.
- *Additionality criterion:* That is, to fund those projects under this mechanism that would not have been funded in the normal course, and therefore funding under AIJ/CDM is required. This can be:
- *Project additionality*: That could be removing financial barriers, technological barriers and/or institutional barriers towards implementation of a GHG project.
- *Offset additionality*: The project should bring about additional GHG reduction.
- *Financial additionality*: This would be in terms the quantum of funds, economic benefits and specific cost per tonne of carbon saved.

- *Technology upgradation & capacity building:* The technology introduced should be replicable across the sector where it is introduced.
- *Additional considerations:* In addition to the above criteria, a project should be beneficial to the country in its totality. Thus, considerations like opportunity costs, risks and additional environment benefits should also be addressed.
- *Learning process:* The project should add to the information base and provide learning and experience for drawing lessons for implementing further AIJ/CDM projects and developing the mechanism.

Under TREAT, TERI would be assisting in developing a portfolio of projects in line with the national priorities of government of India. A number of companies and industries have shown interests in developing such projects. These projects would be screened to identify the ones that are meet requirements of the Japanese AIJ program.

Here, we also recommend that TERI and NEDO could jointly organise business meets between the potential partners to develop this process further.

The partners would then have to negotiate and put forth the proposal for acceptance by their respective governments as AIJ projects. A route of signing Memorandum of Understanding (MoU) between the respective partners and the governments may be followed here.

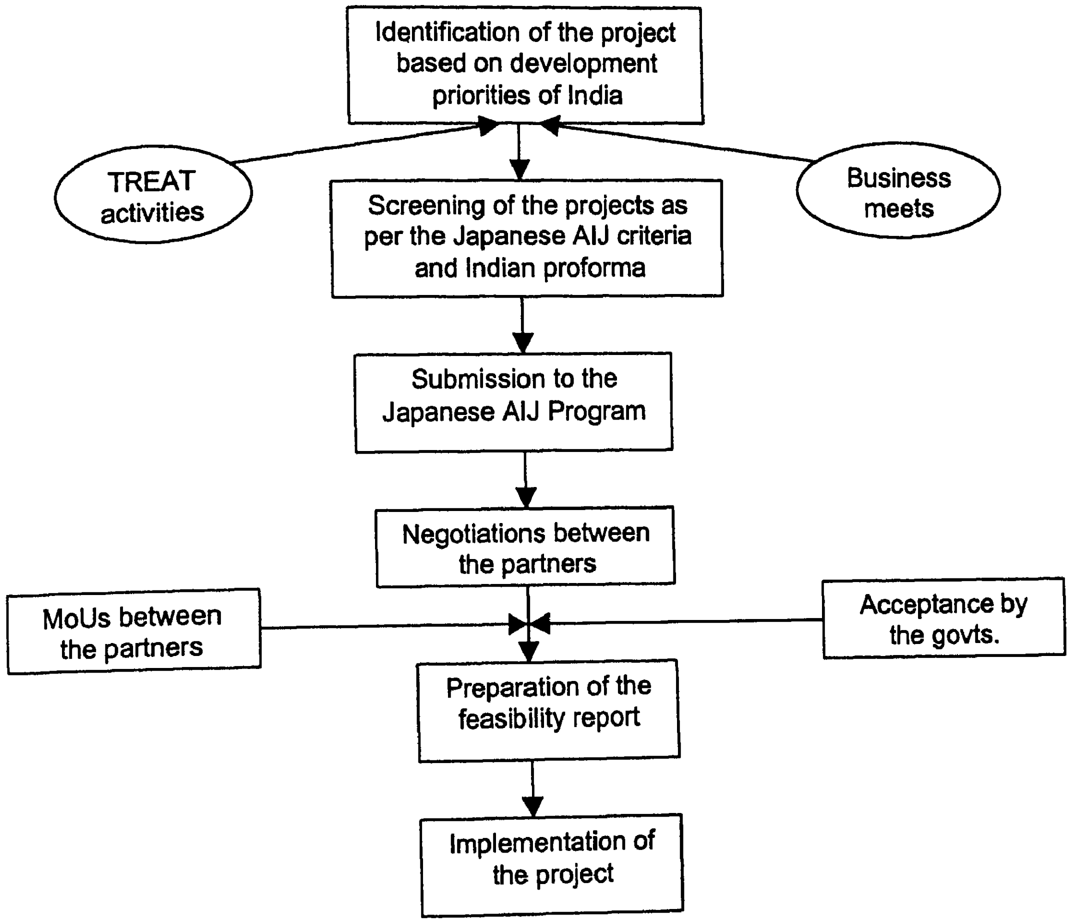


Chart 1 Recommendations for developing an Indo-Japanese AIJ project

AIJ Case Study - I

Introduction of Clean Coal Technologies to reduce GHG emissions[1]

Rationale and Objectives

The ultimate objective of the FCCC is to achieve, within a suitable time frame, stabilization of GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. One of the means of attaining the global objective, is the AIJ-CDM mechanism that enables to meet the respective commitments of the parties. In this, the developed countries have assumed prime responsibility for taking concrete steps in right direction, for reasons carefully considered and included in the FCCC. As the name suggests, the JI mechanism enables countries (developed and developing) to undertake cooperative efforts and measure to reduce the net GHG emissions. In this arrangement the Annex-I countries (industrialized countries) would undertake projects jointly in Non Annex-I counties (usually the developing countries) where the marginal cost of GHG emission reduction is less. Here, the former country or the group of countries would provide technological and/or financial inputs, and in return would get credits for abatement of GHG emissions that occur due to such activity.

The proposed activity of bringing in the advanced power generating technologies like IGCC (integrated gasification combined cycle) and PFBC (pressurized fluidized bed combustion) is consistent with this program. It would substitute for the development of most prevalent pulverized coal fired technology, CO_2 emission reductions and better utilization of natural resources.

General description

India is recognized as one of the large potential markets for energy in the coming years. The demand for electricity is growing at a rate of about 9% and with liberalisation of the economy it is likely to continue to grow faster. So, there is a strong imperative to refurbish old plants and add new capacity.

India is not endowed with large primary energy reserves commensurate with her large geographical area, growing population and increasing final energy needs. Oil and natural gas reserves are limited and account for a small proportion in power generation. Owing to its large reserves (70 billion tons) and easy availability, coal is likely to remain the preferred fuel in the future. It is also,

1 This case study has been prepared by Mr Shahid Hasan, TERI.

however, the source of the largest amount of CO_2 emissions caused during its conversion to electricity.

India currently has an installed capacity of about 87,000 MW of which about 65 per cent is coal based. The per capita electricity consumption in the country is only about 320 kWh. The policy of the Government of India is to make available electricity to the maximum number of people at the cheapest possible rate in an environmentally sustainable manner. However, due to inability to meet the rapidly increasing demand the country is facing an energy shortage of about 10% and peak shortage of 20%. Efforts being made by the government to augment energy supplies include additions to new capacity (thermal, gas, liquid and hydro based), increasing the efficiency of the existing capacity, reduction of transmission and distribution losses, conservation and management of energy. Therefore, in anticipation of increased energy consumption, developing country like India must be provided with clean coal technologies to minimize the undesirable effects of energy development.

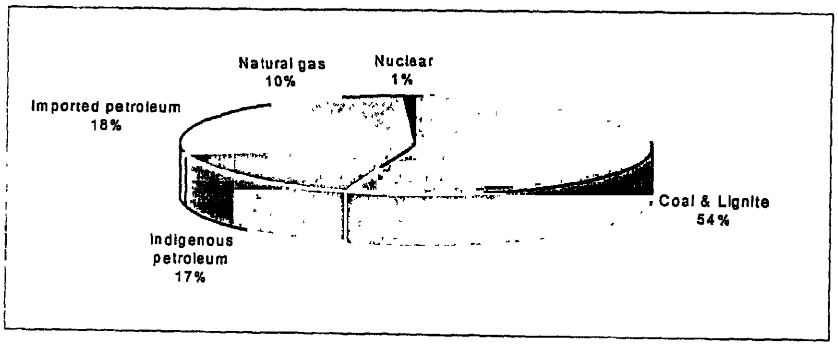


Figure 1 Composition of primary commercial energy supply (1995/96)

Baseline technology and its status in India

Since the mid-sixties, the emphasis has been on establishing the pulverized coal (sub-critical) fired power plant in India. The problems associated with this technique are substantial: inordinate burden on the infrastructure requirements needed to haul coal from the mines to the power plants, resulting in high handling losses and energy consumed in process, low conversion efficiency, and high particulate emissions into the air.

About 64 per cent of the India's electricity is generated from steam turbine driven plant, the steam being produced by combustion of coal. The combustion technology relies heavily on the PC (pulverized coal) fired boiler and is most dominant in India. One of the chief limitations on the efficiency of the standard PC cycle is that it relies solely on a steam cycle for the generation of electricity. It is, therefore, subjected to the efficiency constraints of a Rankine cycle, with

steam temperature dictated by materials consideration. Many of the plants are old, need replacement and are unable to meet increasingly stringent environmental regulations. The existing PC boiler size varies from 30 to 500 MW. The design thermodynamic conversion efficiency is low and limited up to 37 per cent. Though, the average gross efficiency for the same in India is only 31-32 per cent, some of the state owned utility power plants are running at as low as 18 per cent efficiency. This gives a clear indication of manner in which we are consuming our reserves.

The low capital cost, suitability to burn Indian coal, and local availability of pulverised coal (sub-critical) fired technology makes it a preferred choice by the developers in India and a basis for assuming a baseline technology. The technology has almost been standardized and would likely to remain in the market for the next 20 years without any major improvements.

Project Case technologies and its status in the World

There are several advanced coal technology options for increasing power plant efficiencies from the 30-35% levels that are typical of existing coal plants to the range 40-50% (HHV basis). This case study is focused on two sets of options: fluidized bed combustion and coal gasification based systems. The brief descriptions of these technologies are given below.

Pressurized Fluidized Bed Combustion Systems

When a fluidized bed combustor is pressurised, it becomes possible to produce extra electricity by expanding the flue gases from the fluidized bed combustor through a gas turbine, thereby improving overall system efficiency, while reducing the boiler size. Pressurized fluidized bed combustion (PFBC) and the integrated gasification combined cycle (IGCC) is the leading competing advanced coal based power-generating technologies. The principal advantage of PFBC technology in relation to IGCC technology is its simplicity, since it uses just one reactor (a combustor) compared to two (gasifier and combustor) for IGCC technology, which may give PFBC technology a near-term cost advantage compared to IGCC technology. The current generation of PFBC technology is characterised by efficiencies in the range 37-40%. A major limitation of present PFBC technology is that, unlike IGCC technology, it cannot take advantage of continuing advances in gas turbine technology. Future PFBC systems might be able to do this, but they will not have the simplicity that has been the major appeal of current PFBC designs.

GHG emissions per kWh of electricity from combustion are lower for PFBC than for PC systems because of the higher thermodynamic efficiencies of PFBC

units. Moreover, CO_2, emissions from the calcining to freelime of $CaCO_3$ present in the bed in excess of the stoichiometric amount needed for sulfur removal are suppressed in PFBC units are sufficiently high operating pressures (and thus high CO_2 partial pressure). Measured N_2O emissions at the PFBC CHP plant at Vartan, Sweden were the equivalent of about 10% of the CO_2 emissions from coal combustion (Dahl, 1993; Williams, 1997a). With advanced designs it may be feasible to suppress N_2O emissions with PFBC.

Technological features

PFBC technology has the advantages of AFBC technology and in addition the potential for achieving the higher plant efficiency (up to 45 percent) than PC or AFBC (36.5 percent). It also offers lower capital cost than IGCC or pulverized-coal with FGD.

- More than 90% SO_x removal
- NO_x emissions at 100 to 200 PPM
- Fuel flexibility
- Up to 43 per cent efficiency in a combined cycle arrangement

Commercial Availability

PFBC technology is in the early stage of commercialization. Four PFBC units, two in Sweden (135 & 220 MW), one in Spain, and one in the United States, have been placed in operation in the past four years. A fifth 71 MW unit is in initial operation in Japan. Several other demonstration plants are already put into operation or under construction overseas and in Japan.

In case, if PFBC is considered under AIJ-CDM programme for reducing GHG emissions from coal, evaluation of the merit of the technology as a GHG mitigation option must take into account, through appropriate lifecycle analysis and potential GHG emissions in excess of emissions from coal burning, on a case-by-case basis.

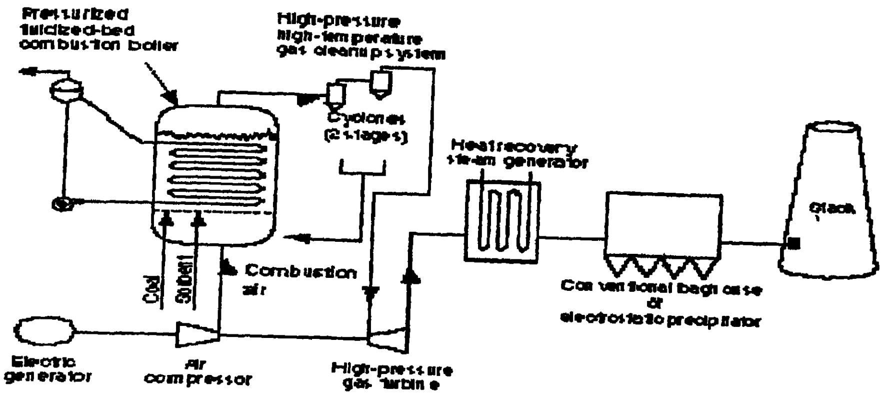


Figure 2 PFBC power plant schematic

Coal gasification and integrated coal gasification/combined cycle technologies

Since the feasibility of firing combined cycle power plants with coal though the use of closely coupled oxygen-blown coal gasifiers was demonstrated in the 94 MW Coolwater Project in Southern California, 1984-1989, there has been much progress in commercializing coal IGCC. This advanced coal technology can take advantage of the continuing improvements in gas turbine technology, making possible much higher efficiencies in power generation than is feasible with now mature steam-electric technology. Moreover, the key enabling technology, the oxygen-blown coal gasifier has many other potential applications in chemicals and fuels productions.

Local air pollutant emission levels for coal IGCC plants can be made as low as from natural gas combined cycle plants far lower than for conventional steam-electric plants equipped with stack gas emission controls. Also, volumes of solid waste must be disposed of are significantly less than for direct coal combustion systems (SFA Pacific, 1993). Moreover, unlike the situation for FBC technologies, there are no significant GHG emissions other than from coal combustion.

In 1994 a 41% efficient 250 MW coal IGCC plant began operation in The Netherlands; in late 1995, a 262 MW coal IGCC plant began operating in Indiana, in the United States; several other coal IGCC plants are expected to be operational soon in various parts of the world (Stambler, 1996). With advanced gas turbines, it is expected that coal IGCC efficiencies will be able to reach 50%. Since the average efficiency of coal-fired power plants in India in 1997 was about 29%, HHV basis, a 50% efficient coal IGCC plant would emit less than 2/3 of CO_2 per kWh as the average coal-fired power plant in India in 1997.

Although present day coal IGCC plants are not yet competitive in strictly economic terms with conventional coal steam electric plants with flue gas

desulfurization, near term improvements in gas turbine technology might make coal IGCC plants fully competitive in many circumstances. In the meantime, coal-rich developing countries intent on acquiring this technology can pursue near term activities that would facilitate later introduction of coal IGCC technology for central station power plants.

Still another way to gain early experience with IGCC would be to gasify refinery residual oils. In several ways, plant costs will often be lower for heavy oil gasification than for coal gasification. For example, solids handling, crushing, and feeding systems are not needed. Moreover, the generally lower levels of ash in heavy oils means less fouling of syngas coolers, so that lower cost designs might be employed. In addition, heavy "refinery bottom" oils tend to be cheap sometimes even cheaper than coal on an equivalent energy basis. As a result, a heavy oil integrated gasification/combined cycle power plant located say, at a refinery will often be able to produce electricity with today's technology at lower cost than a coal steam-electric plant. While this is only a niche market, it offers a basis for gaining experience with gasification technology relating to power generation before the technology is competitive for coal applications in central station plants.

Even when such promising early market opportunities of coal gasification and IGCC technologies have been identified, there will be institutional barriers to their adoption. The barriers to the introduction of these advanced technologies vary from: (I) energy prices; (ii) regulatory policies that restrict the selling of power at market prices to electric grid systems, (iii) a lack of experience using these technologies in developing countries, (iv) industry reluctance to introduce new technologies wit higher real or perceived risks, (v) banker reluctance to fund new technologies that may not be fully proven at commercial scales (v) lack of enforcement of environmental regulations, which businesses to continue to use higher polluting coal burning technologies, to (vi) institutional barriers within governments and international institutional may discourage the introduction of innovative new technologies.

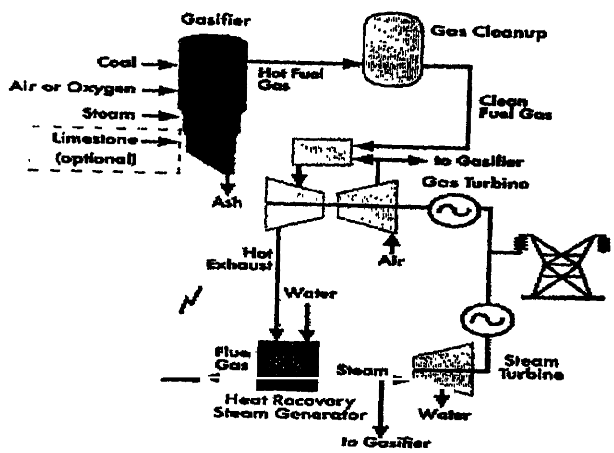


Figure 3 Schematic diagram of IGCC system

Status in India

BHEL has designed and set up an 18 tpd pilot scale pressurized process equipment developed at Hyderabad. This facility has been used for designing 150 tpd pressurized fluidized bed gasifier for setting up a 6 MW of electrical output pilot test facility. This is an entrained-bed gasifier using 46%-ash coal operating around a temperature of 1500°C. This facility has been in operation since 1990.

A 57.2 MW IGCC plant using lignite as feedstock was likely to be operational by November 1997 in Kutch region of Gujarat state. This features the U-Gas gasification technology developed by the Institute of Gas Technology in Chicago. It is based on an air-blown gasifier with a hot gas clean-up system. Hindustan Petroleum Corporation Ltd (HPCL) is planning to set up a 260 MW IGCC plant at Bhatinda in the north Indian state of Punjab based on petrocoke. The petrocoke will be a by-product from their new refinery at the same site. India's growing demand for high speed diesel or gasoil (with low Sulfur distillates) has led HPCL to adopt the delayed coker technology yielding in petrocoke. They have not decided on the technology but do have plans to gasify high-sulphur-content petrocoke to produce syngas and subsequently remove sulfur as H_2S.

The primary constraints to the application of gasification and IGCC plants in India are that the technology needs further demonstration, the costs are higher than those of conventional technologies, and environmental regulations do not require the high SO_2 removal and low NO_x emissions achieved by IGCC.

Commercial availability

Over the last couple of years, integrated gasification combined-cycle (IGCC) power plants have begun penetrating competitive markets. Japan and Taiwan are applying IGCC technology in their first round independent power producer

bidding. A 100 MW IGCC plant at the Cool Water site in America is in operation for the past five years, during which time its performance with a wide variety of feedstock was validated. Since then a number of design and demonstration projects with aggregate capacity of 1300 MW have come up in Europe and US. The following is the list of proposed IGCC plants in the near future.

Table 23 Status of major IGCC projects in world (as of mid-1997)

Customer	Commercial operation	Output (MW)	Application
SCE Cool Water, USA	1984	120	Power/coal
PSI/Destec, USA	1995	260	Repower/coal
Tampa Electric, USA	1996	260	Power/coal
Sierra Pacific, USA	1996	100	Power/coal
Texaco El Dorado, USA	1996	40	Cogen/pet.coke
SUV/EGT-Czech	1996	250	Cogen/coal
Schwarze Pumpe, Germany	1996	40	Power/methanol/lignite
Ilva, Italy	1996	450	Power/blast fum.gas
Shell Pernis, Netherlands	1997	120	Cogen/H2/oil
Buggenum, Netherlands	1998	250	Power/coal
IBIL/Sanghi, India	1998	60	Power/lignite
Fife, Scotland, UK	1998	80	Power/sludge
Sarlux/Enron, Italy	1999	550	Cogen/H2/oil
Exxon, USA	1999	40	Power/H2/CO/pet.coke
Star Delaware, USA	1999	240	Repower/pet.coke
ISAB Energy, Italy	1999	500	Power/H2/steam/oil
Api Energia, Italy	2000	242	Power/oil
Puertollano, Spain	2000	300	Power/coal
GSK, Japan	2001	550	Power/oil
Fife, Scotland, UK	2002	400	Power/sludge
AGIP Petroli, Italy	2002	250	Power/H2/steam/oil

Source: Power Engineering International, January/February 1998

Table 24 General & performance summaries of coal based technologies

General	Unit	PC (SUBC)	PFBC	IGCC
Reference plant size	MW	500	500	400
Gestation period	Years	4	3	3
Fuel		Coal	Coal	Coal
Specific capital cost	US$/Kw	892	1184	1254
PLF	%	68.5	68.5	68.5
Performance				
Operating availability	%	85-90	85-90	85-90
Duty cycle		Base/ Intermediate	Base/ Intermediate	Base/ Intermediate
Plant lifetime	Years	30	30	30
Plant efficiency	%	36	45	58
Auxiliary consumption	%	6	5	20
Gross heat rate	kcal/kWh	2390	1912	1480

Concerns of the Government of India

The energy needs of India are rapidly increasing. Growing industrialisation and urbanisation and an ever-increasing population are contributing factors to this demand. However, these factors have also contributed to the degradation of the environment. Table 25 gives the tentative need based capacity additions planned to meet the required demand, indicating increased reliance on thermal power generation in the Indian power sector. If the current expansion of power generation based on coal continues, the Indian power system, which is expected to grow at 8-9 percent per year in order to fulfil the rising demand, will pose a serious threat to the environment in the coming years.

Though, the total generating capacity of 52,820 MW was identified for implementation in the 9th Plan. However, a capacity addition of only 40,307 MW is envisaged during the 9th plan (1997-2002) because of the financial constraints. The gas accounts for a limited share in thermal capacity additions.

Table 25 Capacity additions envisaged in the 9th, 10th and 11th Plans

Energy Resource	9th Plan (1997/2002)	10th Plan (2002/07)	11th Plan (2007/2012)
Hydro	8,413 (15.9%)	18,060 (39.8%)	25,713 (46.2%)
Thermal*	43,527 (82.4%)	21,430 (47.2%)	26,940 (48.4%)
Nuclear	880 (1.7%)	5,880 (13%)	2,940 (5.4%)
Total	52,820	45,370	55,593

*Includes gas based thermal capacity also, quantity in parenthesis gives the percentage share in total addition.

Source: Fourth National Power Plan: 1997-2012, GoI, CEA, March 1997

All options for large-scale power generation have adverse environmental impacts. Environmental concerns are high on today's policy agenda. The Ministry of Environment and Forest (MoEF), Government of India (GoI) has also promulgated environmental guidelines for thermal power plants. It is said that India's environmental policies are often seen as less ambitious compared to developed countries as most technologies in power projects are chosen based only on direct economic costs and site-specific parameters. The indirect opportunity costs incurred by the nation as a whole due to investments in accompanying infrastructure and increased air pollution are completely ignored. The introduction of environmentally cleaner technologies provides an opportunity to effectively decrease pollution from coal-based power generation, while simultaneously offering potential for lowering power costs as well. The major constraints to their adoption are their higher capital costs (as compared to those for current technology) and the lack of any substantial operating experiences anywhere in the world.

Compatibility with and supportiveness of national economic development and socio-economic and environmental priorities and strategies

India seeks energy through stable energy deliveries at socially acceptable prices and with a minimal damage to the environment. Among the priority actions are to renovate and modernize the existing plants, accelerate development of hydro potential and to promote use of non-conventional methods of electricity generation. The Ministry of Environment and Forest (MoEF), Government of India, has also promulgated environmental guidelines for thermal power plants, which include siting criteria, environmental impact assessment (EIA) and environmental management. Central Pollution Control Board (CPCB) has also prescribed set of guidelines for permissible flue gas emission and liquid effluents for thermal power plants using coal, oil and natural gas fuel. Besides, it has issued guidelines to protect human health, reduce mass loading on the environment to acceptable levels, achieve emission levels based on commercially proven and widely used technologies, follow the current regulatory and technological trends, and promote the use of cleaner fuels and good management practices which would increase energy efficiency and productivity. This project is therefore consistent with the goals and development strategies of the government of India.

Benefits derived from activities implemented jointly projects

Expected global benefits

The proposed activity will help to create environment conducive for deployment of advanced power generating technologies like PFBC and IGCC. Better resource utilisation and less environmental pollution through these technologies will obviate the need for conventional pulverised coal based generation. Gasification of the coal will be the most environmentally friendly way of utilization. Gasification provides an attractive opportunity to overcome these difficulties as the more thermally efficient integrated Gasification Combined Cycle processes now available are more environmentally friendly producing very much lower levels of SO_X and NO_X and unburned hydrocarbons. The more efficient means of power generation also results in a corresponding reduction in CO_2 emissions and therefore, negate the deal with the difficult problem of CO_2 disposal. Thus, the enhancement of the efficiencies and cost-effectiveness of coal based power generation or its promotion is therefore a central task for the future.

Anticipated global benefits of the project include a 24 percent reduction in CO_2 emissions by replacing conventional pulverised coal fired boilers by PFBC systems, and 30 percent reduction by using IGCC technology. Local benefits include virtual elimination of sulfur dioxide (SO_2) and particulates significant reduction in nitrogen oxides (NO_X) emitted by the new technologies. Economy also benefits as a result of less solid wastes generation, small ash handling and ash disposal facility requirements, and waste utilization etc. It is however difficult to estimate the long-term in-direct benefits to the local economy.

Social/cultural benefits

Implementation of the pilot activity will have a positive impact on local air quality and will contribute on an incremental basis to improved air quality regionally; especially will improve ambient air quality in the urban centres (having large power plants nearby), that represent national heritage. It will also have positive impact on the quality of surface and ground water.

Economic benefits

Analysis shows that the replacement of pulverised coal fired boilers to PFBC or IGCC technology is not financially viable as the cost of generation of electricity in both the cases are significantly higher than the market competitive electricity prices.

The additional investment costs for these new technologies can be financially justified by: (a) the reduction in the investment cost for new boilers, since the

capacity of the replaced boiler is downsized; (b) the reduction in annual fuel and maintenance cost; (c) less burden on the infrastructure requirements needed to haul the fuel across the country to various load centres; (d) reduction in handling losses and energy consumption for the movement of fuel; (e) the indirect opportunity costs incurred by the nation as a whole due to GHG emissions and other pollutants which are completely ignored

8. Calculation of the contribution of activities implemented jointly projects that bring about real, measurable and long-term environmental benefits related to the mitigation of climate change that would not have occurred in the absence of such activities

GHG Emissions Reduction

Estimated emissions without the activity (project baseline)

In the absence of any AIJ activity, reengineering and replacement of existing coal fired boilers only at the end of their service life would be the most common choice of plant owners due to a low investment price and the familiarity with coal technology. A shift to new conventional coal fired boilers is chosen as the baseline knowing that this is a conservative choice for calculating the probable emission saving. The abatement effect is thus the difference in emissions between new PC fired boilers and advanced clean coal technologies (PFBC & IGCC).

Estimated emissions with the activity

For both the reference cases, CO_2 emissions are estimated based on; (a) annual operating hours (which is the same for the base and reference cases); (b) for the same plant size; (c) unit emission factors for the given quality of coal. The additional technical parameters and financial assumptions used for the calculation of abatement costs are given in Appendix C, D, and E.

Table 26 Projected emission reductions and abatement cost of coal based plants

Technologies	Fuel	Specific Capital cost (US$/kW)	CO_2 Emissions (MT/yr.)	CO_2 emissions (kg/kWh)	CO_2 abated (kg/kWh)
PC-Base case (500 MW)	Indian coal	892	3.25	1.17	0.0
PFBC (500 MW)	Indian coal	1184	2.60	0.88	0.29
IGCC (500 MW)	Indian coal	1254	2.01	0.80	0.37

Table 27 Cost of CO_2 abatement

Technology	Cost of abatement U$/tonnes (Rs/tonnes)		
	18% IRR	21% IRR	24% IRR
IGCC	31	34	36
	(1240)	(1360)	(1440)
PFBC	52	56	58
	(2080)	(2240)	(2320)

The project cost-effectiveness expressed in the size of the grant per ton of CO_2 equivalents at various values of Internal Rate of Return (IRR) is given in Table 28. The result shows that IGCC is the most promising technology as its incremental cost for GHG mitigation is less than PFBC. The future investment costs of these technologies are likely to drop as a result of both scale-up and efficiency enhancement of gas turbine and gasification technology and thus help fulfil the objective of the AIJ project more cost effectively.

The advantage of reduced emissions of methane from coal mining and transportation of coal is not included in the calculations of emission benefits.

Contribution to capacity building, transfer of environmentally sound technologies and know-how to other Parties, particularly developing country Parties, to enable them to implement the provisions of the convention.

The introduction of advanced clean coal technologies like PFBC and IGCC through AIJ would facilitate the Government's efforts to pursue its environmental priories. The adoption of advanced clean coal technologies would become a financially attractive option if indirect opportunity costs incurred on environmental damage were also taken in consideration.

The scope for using advanced technologies such as PFBC and IGCC to improve cost-effectiveness needs to be demonstrated through pilot investments. Although the technologies are making in roads to the market, their development in India has so far been limited.

The present activity is designed as a catalyst to simulate self-replicable technological and institutional changes that would promote use of PFBC and IGCC technologies for power generation. The proposed activity would also contribute to strengthening of India's capacity to develop experience with design, installation and operation of technologies; create an institutional capability to assess global externalities such as CO_2 emission abatement in project analyses; and to improve implementation of public awareness programs for energy efficiency and conservation.

Appendix A

Methodology for calculating incremental cost of CO_2 abatement

Under the UNFCCC framework, the Annex-I countries are charged with the responsibility of financing the incremental cost of measures taken by the developing countries to achieve the overall objectives of the convention. Because the economic value of the mix of global and local benefits resulting from AIJ-CDM investments are difficult to determine, incremental cost method is used for analyzing the benefits.

It focuses strictly on the estimated costs of proposed projects and compares them to the costs of the next best alternative that delivers the same service to the economy. Specifically, the *gross incremental cost* of a proposed project could be defined as the difference between the total cost of measures taken to implement the proposed project (which will deliver a mix of local and global benefits) and the cost of the least expensive, locally available alternative that could deliver the same principal service to the local economy.

The gross incremental cost of the project less the direct economic benefits to the implementing country or enterprise could be defined as the net incremental cost or just the incremental cost for the purpose of the financial mechanism of the Convention. Thus,

Incremental cost (IC_P) $= GIC_P - DEB_P$

Where

GIC_P = Net present value of the gross incremental cost of the project

DEB_P = Net present value of the direct economic benefits of the project in excess of the direct economic benefits of the baseline alternative

It is difficult to estimate with any confidence the value of direct economic benefits to the local economy. This study does not take into account the direct social or other related economic benefits accruing as a result of project technologies.

Unit Incremental Abatement Cost

King (1992) has proposed several useful metrics for comparing the relative cost-effectiveness of projects taken up for reducing emissions by the developing countries under the ambit of AIJ-CDM. The Unit Incremental Abatement Cost (UIAC) for projects in which incremental benefits exceed incremental costs is as follows:

$$UIAC = (IC_P - IDB_P)/IAE_P$$

Where

IC_P = Incremental cost of project P

IDB_P = Incremental domestic benefits of project P

IAE_P = Incremental quantity of emissions avoided or absorbed by the project

Appendix B

Financial assumptions for calculating the cost of generation

Assumptions about the debt-equity ratio and interest rates along with some other parameters are indicated in the table below

Parameter	Value
Debt -equity ratio	70:30
Indian debt	40%
Foreign debt	60%
Foreign debt interest rate	9.5%
Indian debt interest rate	16.5%
Local term (foreign)	8 years
Local term (Indian)	8 years
Corporate tax rate	35%
Return on equity (RoE)	16%
Tax holiday	5 years
Moratorium (Foreign debt)	2 years
Moratorium (Indian)	2 years
Depreciable life	
Discount rate	18%/21%/24%
$/rupee depreciation	0%

Appendix C

Technical & operating parameters of baseline technology: PC (sub-critical)

Currency Sign for cost & tariff inputs	Rs million	O&M COSTS			
No. Construction years (max 4)	4	Fixed O&M % (@ of % of capital cost)	2.5%		
No. Contract Years (max 30)	30				
		WORKING CAPITAL			
Gross rated capacity, MW	500		Mth	Rs million	
Auxiliary consumption	8%	Fuel Stocks Required	1.0	241	
Net capacity, MW	460	Debtors Outstanding	0.0	0	
Plant Load Factor	68.5%	Creditors Outstanding	1.0	241	
Total Operating Hours	6001	Total Working Capital		482	
Total Gross output, GWh	3000	Interest on working capital@	16.5%	79	
Total Net output, GWh	2760				
		1 Land	1.0%	130	0.7%
Fuel, Rs/tonnes, HHV	1538	2 Site preparation and development	0.5%	65	0.4%
Gross calorific value, kcal/kg	3920	3 Project Development Cost	2.5%	325.00	1.8%
Carbon content	48.5%	4 Margin money (Initial working capital)	5.0%	650	3.6%
Ash content	40.0%	5 EPC cost		13000	72.8%
		6 Contingency	5.0%	650	3.6%
		Total funding without IDC		14820	
Gross Heat rate, kcal/kWh	2390	7 Interest During Construction		3027	17.0%
Net Heat rate, kcal/kWh	2597.8				
Net Plant Efficiency	33.1%	TOTAL FUNDING REQUIRED		17847	100.0%
Fuel consumption, million tonnes/yr.	1.83	Debt	70%	12493	
Annual fuel cost, Rs million	2813	Equity	30%	5354	
		Foreign Debt	60%	7496	
		Indian Debt	40%	4997	
Fuel, Rs/tonnes, HHV	7579	*Total Financing*		*17847*	
Gross calorific value, kcal/kg	9600	EPC Cost/MW		26.0	
Fuel consumption, tonnes/yr.	9976	Total Costs/MW		35.7	
Annual fuel cost, Rs million	76	$/kW		892	
Total annual fuel cost, Rs million	2889	1 U$	40 Rs		
CO_2 emissions, tonnes/yr.	3253042				

Appendix D

Technical & operating parameters of project case technology: PFBC

Currency Sign for cost & tariff inputs	Rs million	O&M COSTS			
No. Construction years (max 4)	3	Fixed O&M % (@ of % of capital cost)	2.0%		
2 Average Operating & Design Parameters		WORKING CAPITAL			
Gross rated capacity, MW	500		Mth	Rs million	
Auxiliary consumption	5%	Fuel Stocks Required	1.0	188	
Net capacity, MW	475	Debtors Outstanding	0.0	0	
Plant Load Factor	68.5%	Creditors Outstanding	1.0	188	
Total Operating Hours	6001	Total Working Capital		375	
Total Gross output, GWh	3000	Interest on working capital @	16.5%	62	
Total Net output, GWh	2850				
		5 Finance : Sources and Uses			
3a Fuel Parameters		1 Land	1.0%	135	0.
Fuel, Rs/tonnes, HHV	1538	2 Site preparation and development	0.5%	92.5	0.
Gross calorific value, kcal/kg	3920	3 Project Development Cost	2.5%	462.5	2.
Carbon content	48.5%	4 Margin money (Initial working capital)	5.0%	925	3.
Ash content	40.0%	5 EPC cost		18500	78.
		6 Contingency	5.0%	925	3.
3b Fuel consumption		Total funding without IDC		21090	
Gross Heat rate, kcal/kWh	1912	7 Interest During Construction		2584	10.
Net Heat rate, kcal/kWh	2013				
Net Plant Efficiency	42.7%	TOTAL FUNDING REQUIRED		23674	100
Fuel consumption, million tonnes/yr.	1.46	Debt	70%	16572	
Annual fuel cost, Rs million	2251	Equity	30%	7102	
Total annual fuel cost, Rs million	2251	Foreign Debt	60%	9943	
CO_2 emissions, tonnes/yr.	2602434	Indian Debt	40%	6629	
		Total Financing		23674	
		EPC Cost/MW		37.0	
		Total Costs/MW		47.3	
		$/kW		1184	
		1 U$	40 Rs		

Appendix E

Technical & operating parameters of project case technology: IGCC

Currency Sign for cost & tariff inputs	Rs million	O&M COSTS			
No. Construction years (max 4)	3	Fixed O&M % (@ of % of capital cost)	2.0%		
2 Average Operating & Design Parameters		WORKING CAPITAL			
Gross rated capacity, MW	500		Mth	Rs million	
Auxiliary consumption	20%	Fuel Stocks Required	1.0	145	
Net capacity, MW	400	Debtors Outstanding	0.0	0	
Plant Load Factor	68.5%	Creditors Outstanding	1.0	145	
Total Operating Hours	6001	Total Working Capital		290	
Total Gross output, GWh	3000	Interest on working capital @	16.5%	48	
Total Net output, GWh	2400				
3a Fuel Parameters		1 Land	1.0%	196	0.8%
Fuel, Rs/tonnes, HHV	1538	2 Site preparation and development	0.5%	98	0.4%
Gross calorific value, kcal/kg	3920	3 Project Development Cost	2.5%	490.00	2.0%
Carbon content	48.5%	4 Margin money (Initial working capital)	5.0%	980	3.9%
Ash content	40.0%	5 EPC cost		19600	78.1%
		6 Contingency	5.0%	980	3.9%
3b Fuel consumption		Total funding without IDC		22344	
Gross Heat rate, kcal/kWh	1480	7 Interest During Construction		2737	10.9%
Net Heat rate, kcal/kWh	1850				
Net Plant Efficiency	46.5%	TOTAL FUNDING REQUIRED		25081	100.0 %
Fuel consumption, million tonnes/yr.	1.13	Debt	70%	17557	
Annual fuel cost, Rs million	1742	Equity	30%	7524	
Total annual fuel cost, Rs million	1742	Foreign Debt	60%	10534	
CO_2 emissions, tonnes/yr.	2014436	Indian Debt	40%	7023	
		Total Financing		25081	
		EPC Cost/MW		39.2	
		Total Costs/MW		50.2	
		$/kW		1254	
		1 U$	40	Rs	

AIJ Case Study II

R&M in thermal power plants*

The overall objective of the R&M program of the old coal fired thermal power plants is to improve the efficiency and also to adopt a new generation clean coal technology of Pressurized Fluidized Bed Combustion Boilers (PFBC) in India. The adoption of PFBC in the retrofitting of the old pulverized coal fired thermal power plants will not only boost the amount of power available but also reduce the requirement of a number of green field projects which are currently being planned. The adoption of PFBCs will reduce the negative environmental impacts of the new power plants and also the indirect negative impacts due to the emissions of GHGs in the mining and transportation of coal to the green field projects. As a party to the UNFCCC, India has identified this as one of the priorities.

Sector background

(i) National Strategy/action plan

Faced with acute financial limitations, private power participation has been actively sought to rescue the situation. Even after the government's announcement of opening the power sector for private participation, the growth has not been very encouraging. The costs of establishing power supply facilities and fuel inputs have also been increased over the years. Thus, keeping in view the need to fill in such a huge demand by the addition of new capacity in generation, adoption of a rigorous renovation and modernization program in the refurbishing of old plants will significantly help in alleviating the power situation in the country. The R&M program suggested under this proposal will not only increase the plant load factor (PLF) but also increase the output in terms of capacity from the same unit by about 10-12 percent. The other benefit of adoption of this technology is reduced carbon dioxide emissions to the extent of 14 percent. The pollutants like SO_x and NO_x will be almost nil. The utilities and the IPPs must maintain the lowest cost of generation simultaneously reducing the emissions.

Keeping this aspect in mind the Government of India (GoI) has since recognized R&M as the alternative offering much cheaper and quicker way to add capacity, it has been decided to accord the highest priority to this area. The GoI has brought out a comprehensive R&M policy in1995 (Privatized

* This case study draws upon the work done under TERI, 1997.

Renovation & Modernization of Power Plants: Policy Guidelines issued under D.O. letter NO. R- 1/94-IPC DT. 28 Oct. 1995) which outlines some of the options available for encouraging private investment in this vital area.

The poor performance of thermal power stations is a matter of concern. On analyses of various causes for discouraging performance, it has been observed that timely maintenance of power stations is being overlooked due to financial constraints. Accordingly a massive program of R&M of thermal and hydro power stations may have to be undertaken during the Ninth plan as well as subsequent plan periods to improve the efficiency and also to augment the generating capacity.

R&M program phase - 1 of GoI

During the seventh plan period, the first R&M Program of thermal power stations was initiated. The program covered 163 thermal units, comprising 13750 MW capacity in 34 selected thermal stations all over the country at a total revised estimated cost of Rs. 1165 crores. Out of this an amount of Rs. 500 crores was approved by the GoI under Central Loan Assistance program to various SEB's to supplement their efforts for R&M of old stations. The physical implementation of the scheme started from the year of its launching i e. 1984-85. Though the scheme was required to be completed by the end of 7th plan even after partial implementation of the R&M scheme significant benefits started accruing. As per the CEA's published data, against additional Energy target of about 7000 million units per annum from R&M schemes, the actual energy generated during 1990-91 was 10700 million units which is equivalent to new capacity addition of 2100 MW assuming a PLF of 58 percent. The total expenditure towards the R&M schemes up to the year 1990-91 was Rs. 830 crores . It is thus observed that capital investment of Rs. 8400 crores was saved (assuming Rs. 4 crores as cost for adding 1MW of thermal capacity) by spending Rs. 830 crores only , resulting in a net saving of Rs 7570 crores.

R & M program phase-2 of the GoI

Based on the encouraging results of R&M - 1 program, the phase-II of the R&M program of thermal power stations was initiated during 1990- 91 for implementation during eighth plan period. Under this program, 44 thermal power stations consisting of 198 thermal units aggregating to total capacity of 20,869 MW at an estimated cost of Rs. 2383 crores were covered. However, the pace of progress of this program has been very slow mainly due to paucity of funds with SEB's. In order to tide over the resources constraints, GoI announced liberalized economic policy in 1991 allowing for private investments, including foreign investments, into all areas of the power sector. In this connection GOI

also issued policy guidelines in October 1995 for attracting private investments in R&M works in order to put the required thrust in this important area of power. However, the response has not been encouraging.

Strategies for formulation of R&M and life extension schemes

The installed generating capacity of the country being predominantly thermal, the Renovation and Modernization and life extension of thermal stations is the most economic way of reducing the widening gap between electricity demand and supply. In a thermal station, the boiler is the major equipment in meeting the energy production needs. A strategic approach is required to optimize and extend the life of these units. Initially, routine maintenance is sufficient to maintain high availability. However, as the unit matures, its components begin to wear out needing more steps to extend the life of equipment and to increase its efficiency and availability. Therefore, the key issues to consider when optimizing the units include understanding how the age, identifying the critical components, and determining the general types of possible upgrades. These elements are then combined with operating experience and equipment condition assessments to develop integrated strategic plans for individual units.

Power plant ageing and life extension

The normal life of a thermal power plant is about 25 to 30 years depending upon the design and use of the unit. After this period, the ageing process becomes noticeable. Forced outages and maintenance costs increase and availability declines. The degradation of components due to erosion, corrosion, creep and fatigue lead to unit failures. The higher cost of new plants and the need to keep the older plants running brought about the new strategy of life extension. However, recent environmental regulations have a strong influence on the life extension strategies developed for older units. Therefore, any life extensions programme that includes a capacity increase must consider the possibility that pollution control equipment may be required. The capital involved in a life extension programme is generally about 50% the cost of a newer plant with similar capacity. While the driving force for a life extension programme may be to stretch present resources to meet current demands, an extension program can also achieve a return on investment in the older plant by way of a lower heat rate, higher capacity, reduced routine maintenance, and lower forced outage rates.

Link to sustainable development planning

The proposed programme of Renovation and Modernization of old coal-fired thermal power plants by the adoption of PFBC boilers combined cycle

technology will encourage the widespread use of this technology for R & M. The increase capacity levels, life extension, higher PLF and a highly environmentally benign technology are some of the significant benefits of this technology in the proposed R & M program. The capital costs per MW of new capacity available is expected to be much lower than the new greenfield projects which require significant investments in the development of infrastructure. The primary advantage of retrofitting the existing power plants will be that the initial investments for the development of the project will be significantly lower because the coal linkages are already established and the basic infrastructure is already in place. The other benefit will be low gestation period, lower capital cost, lesser land and water requirements and lower auxiliary power consumption than the conventional thermal power plants.

Objectives

The primary objective is to promote PFBC and the adoption of combined cycle coal fired technology, which is a low GHG emitting technology in the old pulverized coal fired power plants. The proposed program will help in removing the barriers to the large-scale application, implementation, and dissemination of least-economic cost energy efficient technology.

Improve the viability of the technology- a coherent R & M program with the adoption of PFBC will also reduce the implementation cost of the technology. The planned activities are expected to aggregate the financial and techno-economic viability of the technology, creating distribution channel/channels for repair and maintenance network.

Further technology development would be supported through technical assistance and training. In addition to fulfilling the program objective of the climate change, the project is expected to consolidate the Government of India's effort to expand the role of low GHGs energy technologies for power generation and to further a long term program for promoting the PFBC systems in India. The project would provide technical assistance and capacity building in the advanced clean coal technologies.

Benefits of R&M Programme

The reduction of carbon emission reduction by R&M of old coal fired thermal power plants by the adoption of PFBC boilers combined cycle technology falls has two major benefits - energy efficiency & energy conservation and reducing the long term costs of low greenhouse gas-emitting technologies. The performance of the thermal power plants in India has been much below their design levels. Taking up the R&M program by the adoption of the new technology PFBC will not only enhance the efficiency of the existing power plant

by approximately 12 percent but also reduce GHGs significantly over its life cycle. PFBC is an advanced clean coal technology, which has been tried successfully in many developed countries and the technology will have to imported and demonstrated with Indian coals. The current policy of the GoI has not attracted the private sector inspite of the attractive financial package. The SEBs who are the current owners of most of the thermal power plants are not in a position to run the plants efficiently neither they have the financial resources need for R&M.

AIJ Case Study - III

Bagasse-Fired Cogeneration Plants in Sugar Mills

Objective

Reduction of carbon emissions by the adoption of state-of-the-art cogeneration in sugar cane industry and feeding the surplus power to the grid.

Sugar Sector

India is the largest producer of sugarcane in the world. The current production of sugar in the country is over 12 million tons per year. The sugar industry has been growing at an annual rate of around 10 percent per annum.

Compatibility with national development priorities

Bagasse based cogeneration is line with the national development priorities in India. It meets the criterion of energy and resource conservation. The Ministry of Power has announced a cogeneration policy, whereas Ministry of Non-Conventional Energy Sources has announced various incentives for the promotion of the bagasse based cogeneration.

Project Additionality

The installation of high pressure state-of-the-art plants in the sugar mills would have been difficult if the AIJ route is not followed. The project bring about high efficiency in the sugar mills, and provides a large capacity state-of-the-art off season fuel supply

Case Study

The bagasse-fired cogeneration case study is for the sugar mills of Uttar Pradesh, specifically in Daurala and Simbhaoli, in order to examine whether bagasse fired cogeneration can be successfully implemented in these mills.

The study envisages replacing or retrofitting existing boilers and installing cogeneration equipment like high-pressure multi-fuel boilers, high efficiency condensing extraction turbines and advanced pollution control equipment at the sugar mill.

The analysis deals with two important issues:

i) the costs avoided by the State Electricity Board (SEB) if it purchases power from the cogeneration plant rather than the thermal power plant. This can serve as a measure for financial additionality.

ii) demonstration that net CO_2 emissions can be reduced from the Indian power sector by the implementation of such projects. The chosen mechanism for achieving the above is `AIJ'. These AIJ benefits have been quantified in terms of the carbon offset costs.

Avoided costs analysis

One way to find the value of power generated by independent producers is to estimate the `Avoided Costs (ACs)' from the perspective of the utility. These ACs are costs of power generation and fuel that the power company no longer needs to incur because of the availability of power from an alternate source, such as the cogeneration plant.

The purpose of estimating ACs is to maintain the SEB and its ratepayers in the same financial position it would have been had it not made a purchase from the cogenerating facility. Thus, ACs are calculated with respect to the value of the power to the SEB and are not related to the costs that the cogenerating facility incurs in producing the power, based on 1995 prices. This formulation of ACs is designed to avoid imposing a burden on the SEB's ratepayers*.

The Proxy method has been used for determining ACs. The proxy chosen is a new 500 MW thermal (coal) power station (TPS) because the power generation-mix in Uttar Pradesh (UP) is heavily weighted towards thermal (approximately 70 percent). A financial analysis yields the costs avoided by the UPSEB, which are equal to the unit costs of generation of the TPS.

Assumptions for 500 MW TPS

Lifetime:	25 years
Plant Load Factor:	0.68
Capital Investment:	4 crores per MW
O&M Costs:	2.5% of the capital costs
Coal characteristics:	F grade coal, calorific value 4000 kcal/kg
Pithead Coal Cost:	Rs 450 per ton

* Fink & Beaty, Standard Handbook for Electric Engineers, 12th edition, 1987, Mc Graw - Hill Book Company.

Transport cost for coal:	Rs 265 per ton (@ Rs 0.53 per km per ton by rail)
Oil Costs:	Rs 7400 per kilolitre
Specific coal consumption:	0.63 kg per kWh
Specific oil consumption:	3 ml per kWh
Auxiliary power consumption:	6.5% of generated power
Transmission & Distribution losses: nil	
Inflation:	nil
Rate of discount:	12%
Depreciation:	7.5%
Debt equity ratio:	4:1
Rate of return (on equity):	16%
Commercial rate of interest:	14%
Annual interest on working capital:	0.2 * (fuel cost + O&M cost)/6
Corporate income tax:	nil*

Results

On the basis of these assumptions, the costs avoided by the SEB are Rs 2.42 per KWh†.

Carbon offset analysis

The AIJ benefits of the project were determined by calculating the net cost of carbon offsets for the project. Two scenarios for cogeneration have been examined. In the first case, the sale of steam and electricity to the sugar mill, and purchase of bagasse by the cogeneration plant are assumed to take place at the market price. In the second scenario, it is assumed that the sugar mill supplies the bagasse to the cogeneration plant free of cost in exchange for electricity and steam.

* An assumption has been made that only the guaranteed rate of return (16%) has been attained by the company. Any additional income will incur a tax of 50% with the provision of a 5 year tax holiday.

† This calculation of avoided costs assumes a flat tariff for the ratepayers of the UPSEB. As the UPSEB is considering demand side management in the future, in order to smoothen the load curve a two-part tariff may be introduced.

A new 500 MW thermal (coal) power station (TPS) has been taken as the baseline* from which carbon reductions will be computed. The costs of equivalent cogeneration projects (in both scenarios) and the TPS were annualised, and the carbondioxide offset costs in dollars per ton of carbon abated was calculated as follows:

$$IAC\ (\$/ton) = \frac{-(COST_{COGEN} - COST_{TPS})}{(CO2_{COGEN} - CO2_{TPS})}$$

where, IAC : Incremental Abatement Cost
Cost : NPV of total cost
CO_2 : Cumulative CO_2 emissions

In the formula for incremental abatement cost, the numerator denotes the difference between the total cost of measures taken to implement the proposed project and the cost of the locally available alternative that could deliver the same principal service to the local economy, being part of the country's baseline development. The denominator gives the difference between the total CO_2 emissions in the proposed project and the baseline project.

Assumptions for Cogeneration Plants

Bagasse-fired generation:	46.262 MW for 200 days per year
Coal-fired generation:	63.332 MW for 130 days per year
Lifetime:	25 years
Plant Load Factor:	0.8 (on-season)
	0.85 (off-season)†
Capital Investment:	3 crores per MW
O&M Costs:	5% of the capital costs
Coal characteristics:	steam coal, calorific value 4500 kcal/kg
Coal Cost:	Rs 1900 per ton‡
Bagasse Cost:	Rs 450 per ton
Specific coal consumption:	0.715 kg per kWh

* For the UPSEB, thermal plants account for 70% of the load. Therefore, a factor of 0.7 has been used to make the carbon dioxide emissions of the TPS representative for the state of UP.

† The PLF in off-season is greater than on-season because there may be disruptions in bagasse supply from the sugar mill.

‡ This includes the cost incurred in transporting coal by road; the alternative of rail transportation is not feasible for Daurala and Simbhaoli.

Specific bagasse consumption:	2.25 kg per kWh
Steam price:	Rs 300 per ton*
Rate of discount:	12%
Inflation:	nil
Auxiliary capacity requirement:	2 MW
Capacity requirement of the sugar mill:	10 MW

Results

Based on these assumptions and taking a CO_2 emission coeffient of 1.62 for the TPS and 2.14 for the cogeneration plants, the carbon offset costs were obtained as follows:

Plant	Offset Costs ($/Ton)
Cogeneration (Scenario I)	-4.36
Cogeneration (Scenario II)	4.17

An IAC of U.S. $ -4.68 per ton indicates that the cost of abating CO_2 emissions by generating electricity from the cogeneration plant (under scenario I) per ton of CO_2 abated is US $ 4.68 less than that incurred by the TPS . This makes the cogeneration plant a no-regrets option, because it is economically viable even if the global environmental benefits of reduced CO_2 emissions are not taken into account. However, the second scenario, entails an incremental cost of U.S. $ 3.57 per ton of carbon abated.

Sensitivity analysis

The sensitivity of the results to the price of bagasse was determined by calculating the incremental abatement cost for three different prices for bagasse: Rs. 450, Rs. 700, and Rs. 900. The following results were obtained:

* The assumption here is that steam is sold at a price equal to its cost of production (Rs.300/ton is the cost of production).

Bagasse Price (Rs/Ton)	Offset Costs ($/Ton)
450	-4.36
700	5.02
950	14.40

The results indicate that as the price of bagasse increases, the incremental abatement cost increases.

AIJ Case Study - IV

Adoption of Precalcinator in Dry Process Cement Plants*

In this case study, the adoption of precalcinator in an existing dry process plant is considered to illustrate how various AIJ criteria could be addressed.

Project Aim

To introduce precalcinator in an existing dry process cement plant to reduce its thermal power consumption and hence CO_2 emissions.

Description of Technology

Precalcination is a process of treatment of the raw meal before feeding to the main kiln. In the precalcination process the preheated raw meal is heated at a lower temperature than in the main kiln. Amount of calcination achieved in this process is about 85-90%.

Status quo of the technology

Most of the new cement plants in India have come-up with precalcinator kilns. Analysis of kilns set-up during the period 1981 to 1991 shows that of the 27 dry process kilns, 15 have incorporated precalcination technology, 8 of them are operating with 5 stage preheater, and one has gone for 6 stage preheater. The cement plants that have gone for the precalcinator and other technologies have benefited from reduced energy consumption and improved kiln life. However many of the small plants still find it financially not viable to go for this technology. Also, the technology to a large extent is still imported from foreign companies.

The proposed project would benefit the domestic companies in obtaining much needed financial resources to adopt better technology and the collaborating foreign company would benefit because of lower CO_2 abatement cost it faces in the domestic company.

Baseline

As the technology itself exists in other Indian plants, one might want to consider the average CO_2 emissions from cement industry as baseline. However, since AIJ projects are expected to consider project level baselines only, the CO_2

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* This has been prepared by Mr kavi Kumar, TERI.

emissions from an existing dry process plant without precalcinator kiln can serve as baseline here.

Real measurable and long-term environmental benefits

Lesser thermal energy requirement in the cement plants with precalcinator kiln implies lower coal consumption and hence lower CO_2 emissions. Hence the project achieves real and measurable CO_2 emission reductions.

Compatibility with national development priorities

The project matches with the national priorities because:

- It targets energy conservation;
- It contributes towards modernization of cement industry;
- It can make use of low grade coal which is abundant in India;
- It results in exhaust gases that contain lesser nitrous oxides (NOX) and hence benefits local environment.

Offset additionality

The project is expected to bring about real and measurable benefits in CO_2 emission abatement.

CO_2 abatement cost

Detailed assumptions and steps in calculating the abatement costs are provided in the appendix. Based on those assumptions the CO_2 abatement costs for different levels of return on equity are shown in table 28.

Table 28 CO_2 Abatement Cost

Return on Equity	Abatement Cost	
	Rs./ton	US $/ton
18%	318.3	8.2
21%	403.4	10.3
24%	491.2	12.6

The assumptions made while calculating the Incremental Cost

Marginal tax rate:	43%
Debt equity ratio:	2/1
Cost of foreign debt:	9.5%
Cost of domestic debt:	18.5%

Operating life:	20 yrs
Tax life of the system:	1 yr
Return on equity:	18/21/24%
Calorific value of coal:	3920 kcal/kg
Carbon content of coal:	48.5%
Cost of coal:	Rs. 1538 / ton
Exchange rate:	Rs. 39 per $
Plant capacity:	3000 tons per day
Capital required for new technology:	Rs. 1860 million
Thermal energy saved:	1.72 GJ/ton

Calculation Procedure

Step 1: Annualized capital cost per ton of cement is calculated using the Capital Recovery Factor - Financial (CRF_f). CRF_f is estimated using the following formula

$$CRF_f = \quad (1-TR) \quad * \left(1 - \quad TL * CRF(r, TL) \right)$$

Where, r is the after-tax cost of capital

$= f_e r_e + (1-TR)^* f_d r_d$

f_e is the fraction of equity in project financing

f_d is the fraction of debt in project financing

r_e is the return on equity

r_d is the cost of debt

TR is the marginal tax rate

OL is the system operating life

TL is the system tax life

Step 2: Annual O&M cost per ton of cement is added to the annualized capital cost per ton of cement to arrive at the gross incremental cost per ton of cement.

Step 3: Value of energy saved per ton of cement is deducted from the gross incremental cost to determine the net incremental cost per ton of cement.

Step 4: Net incremental cost per ton of cement is divided by the amount of CO_2 saved per ton of cement to calculate the CO_2 abatement cost.

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Annexure I

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Annexure II

Map 1. Power stations in India

Hydro Power Stations		Thermal Power Stations		Nuclear Power Stations	
S. No.	**Name**	**S No.**	**Name**	**S No.**	**Name**
1	Bhakra	1	Anpara	1	Raps
2	Dehar	2	Badarpur	2	Narora
3	Pong	3	BhatindaGNDT	3	Kakrapar
4	Baira Siul	4	Bhusawal	4	Tarapur
5	Salal	5	Bokaro A&B	5	Kalpakkam
6	Mukerian	6	Chandrapur STPS	6	Kaiga
7	Rana Pratap	7	Chandrapura (Bihar)	7	Trombay
8	Chibro	8	Dadri		
9	Ramganga	9	Farakkaha STPS		
10	Ukai	10	Gandhinagar		
11	Pench	11	Khalgaon		
12	Bansagar	12	Khaparkheda		
13	Koyna	13	Kolaghat		
14	Sileru	14	Koradi		
15	Nagarjuna	15	Korba STPS		
16	Srisailam	16	Korba West		
17	Sharavathy	17	Kota		
18	Kalinadi	18	Kothagudem		
19	Varahi	19	Mettur		
20	Idukki	20	Nasik		
21	Sabaragiri	21	Neyveli		
22	Kundah	22	Obra		
23	Mettur	23	Panipat		
24	Kadamparai	24	Parli		
25	Hirakud	25	Patratu		
26	Balimela	26	Raichur		
27	Rengali	27	Ramagundam		
28	Kolab	28	Rihand		
29	Tanakpur	29	Ropar		
30	Chamera	30	Sanjay Gandhi		
31	Sanjay	31	Santhaldih		
32	Lower Jhelum	32	Satpura Sami		
33	Shanan	33	Singrauli STPS		
34	A.P.Sahib	34	Talcher		
35	Mahibajaj	35	Trombay		
36	Rihand	36	Tuticorin		
37	Khodri	37	Ukai		
38	Chilla	38	Unchahar		
39	Hansdeo Bango	39	Vijaywada		
40	Kadana	40	Vindhyachal		
41	Gandhi Sagar	41	Wanakbori		
42	Bhira	42	Cuddapah		
43	Machgund	43	North Madras		
44	Jog	44	Ib Valley		
45	Supa	45	Dhanu		
46	Kopili				
47	Loktak				

Annexure - III

Map 2 : Location of the major Iron & Steel Plants in India

S.No	Name
1	Jamshedpur
2	Bokaro
3	Vishakhapatnam
4	Bhilai
5	Burnpur (IISCo)
6	Durgapur
7	Raurkela

re - IV

Location of the major cement plants in India

Name	S.No	Name
CCI Ltd	55	Birla Gr
India Cem	56	Birla Gr
Madras Cem	57	Narmada Cem
Juari	58	Shree Digvijay
KCP	59	Mawmluh
Birla Gr	60	CCI Ltd
Kistna	61	Birla Gr
ACC Ltd	62	Birla Gr
Andhra Cem	63	Birla Gr
Birla Gr	64	Birla Gr
Panyam	65	L&T Cem
Priyadarsani	66	ACC Ltd
Rassi	67	Jaypee Bela
Sri Vishnu	68	Jaypee Rewa
CCI Ltd	69	ACC Ltd
Andhra Cem	70	Birla Gr
Andhra Cem	71	CCI Ltd
CCI Ltd	72	Modi
CCI Ltd	73	CCI Ltd
ACC Ltd	74	JK Gr
Kalyanpur	75	TISCO
Khalari	76	Birla Gr
Rohtas	77	IDCOL
ACC Ltd	78	L&T Cem
Sone Valley	79	OCL India
TISCO	80	Guj Ambuja
CCI Ltd	81	Birla Gr
Shree Digvijay	82	Birla Gr
Dwarka	83	DLF
Guj Ambuja	84	Jaipur Udyog
L&T Cem	85	ACC Ltd
Mehta Gr	86	JK Gr
Narmada Cem	87	Birla Gr
Tata Chemicals	88	Cement Works(G)
HMP Gr	89	Birla Gr
Mehta Gr	90	JK Gr
Sevalia	91	Shree
ACC Ltd	92	Sriram
CCI Ltd	93	JK Gr
ACC Ltd	94	TN Cem Corp
Guj Ambuja	95	Madras Cem
CCI Ltd	96	TN Cem Corp
J&K cements	97	Chettinad
Malabar	98	Dalmia
Kanoria	99	ACC Ltd
CCI Ltd	100	Madras Cem
Birla Gr	101	India Cem
Birla Gr	102	India Cem
HMP Gr	103	UP state Cem Corp
Birla Gr	104	UP state Cem Corp
Visvesvaraya	105	UP state Cem Corp
ACC Ltd	106	Birla Gr
L&T Cem	107	Damodar
ACC Ltd	108	Birla Gr